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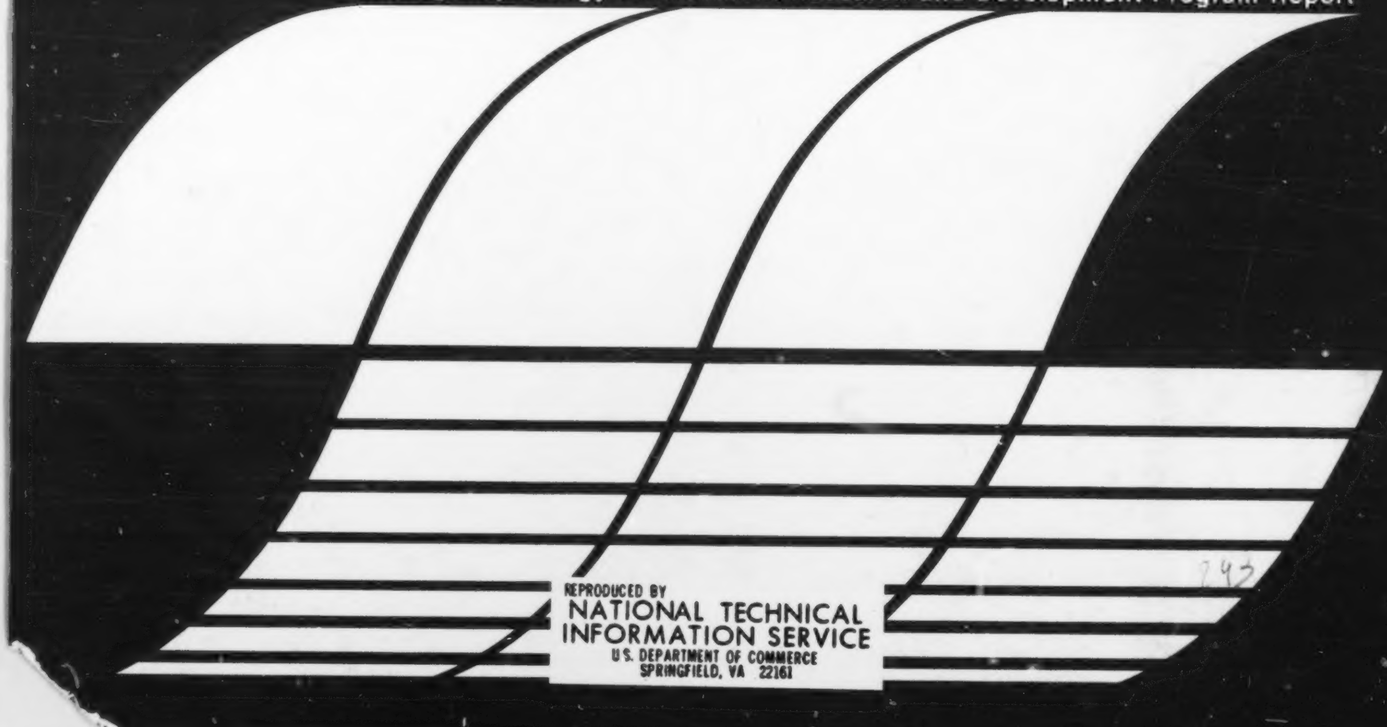

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	Mr. William N. McCarthy, Jr.	202/755-2737
EPA Contacts:	Mr. Morris H. Altschuler	202/755-0205
	Mr. Robert M. Statnick	202/755-0205

16. ABSTRACT

This report covers the environmental, operational, and economic aspects of thirteen (13) current and developing technologies as applied to the generation of electric power, steam generation, and the conversion of fossil energy into alternative forms. The following technologies are addressed: 1) Conventional Boiler; 2) Diesel Engine; 3) Fluidized-Bed Combustion; 4) Combined Cycle Systems; 5) Low/Medium-Btu Gasification; 6) Chemically Active Fluid Bed; 7) Indirect Coal Liquefaction; 8) High-Btu Gasification; 9) Surface Shale Oil Processing; 10) In Situ Shale Oil Processing; 11) Direct Coal Liquefaction; 12) Fuel Cells; and 13) Magnetohydrodynamics (MHD). The present status of each technology is discussed along with prospects for commercial implementation.

Some of these processes such as conventional coal-fired boilers and combined cycle electrical utility systems are currently being applied to varying degrees for base, intermediate, and peaking services at power plants. When using cleaner fuels (distillate oil and gas), some addressed processes require only limited environmental controls. Due to the shortages associated with currently utilized cleaner fuels, greater emphasis is being placed upon the rapid development of alternative technologies capable of using the Nation's more abundant reserves of coal, oil shale, and heavy crude oil in an environmentally acceptable fashion. One such technology, permitting the direct use of high-sulfur coal, is fluidized-bed combustion which is currently being demonstrated in industrial-sized units. Other technologies involve the conversion of coal to a suitable liquid or gaseous fuel for use in existing equipment and for advanced technologies under development, and the conversion of oil shale to a commercial grade oil product. Also discussed are some of the more remote processes, such as fuel cells and MHD, which offer the prospect, when substantial technical hurdles are overcome, for improved efficiencies while maintaining environmental compliance.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS			b. IDENTIFIERS/OPEN ENDED TERMS		c. COSATI Field/Group	
Air Emissions Chemically Active FB Combined Cycle Conventional Boiler Diesel Generators Efficiency Energy Conversion Energy Efficiencies	Environment Fluidized-Bed Fuel Cell Fuel Conversion Fuel Processing Technologies High-Btu Gasification Liquefaction Liquid Effluents Low-Btu Gasification	Magnetohydrodynamics Oil Shale Performance Power Generation Shale Oil Solid Waste Thermodynamic Efficiencies	BI-GAS CO_2 Acceptor Combustion Engineering, Inc. Fischer-Tropsch H-Coal HYGAS Koppers-Totzek	Lurgi Mobil Process Occidental Modified In Situ Solvent Refined Coal SRC Synthane Synthoil TOSCO II Westinghouse Electric Corporation	10A 10B 43E 43F 680 97B	97F 97G 97I 97K 97L 97R

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FOR

OFFICE OF ENVIRONMENTAL ENGINEERING AND TECHNOLOGY
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PREFACE

As a result of significant increases in the cost of fuel and the desire for a clean environment, there has been increased emphasis placed on economic and environmental aspects of fuel utilization. These factors contributed to the need for a report that would address selective fuel utilization and conversion technologies. This being the case, the EPA, Office of Environmental Engineering and Technology (OEET) felt it imperative to sponsor such a report in a form suitable for general distribution.

This effort was completed in fulfillment of Task A of EPA Contract No. 68-01-4999, Morris H. Altschuler and William N. McCarthy, Jr., EPA Project Officers.

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EXECUTIVE OVERVIEW

Approximately one-third of the total energy used annually in the United States is devoted to the generation of electricity. The U. S. Department of Energy estimates that by 1990, this share may substantially increase. To meet this increasing demand will require the substantial addition of generating capacity.

Currently, about 48 percent of our electric energy is produced from coal-fired plants, with the combined outputs from nuclear and hydroelectric contributing another 24 percent. This still leaves about 28 percent being produced with natural gas and oil, whose price and continued availability lack the stability on which to base a reliable electric power generating industry. Further, these increasingly scarce fuels are required for heating, industrial purposes, and transportation.

Technologies must be developed which can make greater use of our abundant reserves of coal in an environmentally acceptable fashion. The technologies addressed in this report are those which potentially could use our available and under-utilized fossil fuel resources (coal, heavy crudes, and oil shale) in an environmentally acceptable manner. Some are more costly than others and this has to be weighed against their relative operational and environmental aspects.

This report is intended to give the reader a better understanding of the current status of possible options as they might be applied to the future generation of electricity and other energy needs. Brief coverage of the technologies follows. For a more comprehensive assessment, the reader is referred to the individual sections.

In the case of conventional coal-fired steam-electric power plants, current efficiencies range from approximately 31 to 38 percent. The prospect for the foreseeable future is that newer plants will have efficiency values below 40 percent. It is unlikely that truly operational efficiency values in excess of 40 percent from conventional plants will be realized within the foreseeable future. In the absence of pollution control measures, coal fired steam-electric plants would provide very substantial undesirable environmental impacts. However, the current state-of-the-art of environmental control and resulting control measures are capable of substantially mitigating currently identified undesirable pollution and other environmental effects. Continuing environmental control activities are expected to provide the means of control for the near-term any potential overall undesirable effects resulting from increasing use of coal to fire steam-electric plants.

Diesels have been commercially utilized in excess of 80 years. They are used extensively to power moderate size stationary electric generators for a variety of services. Even though the output of a large diesel generator is small compared to the output of a typical utility fossil-fuel steam-electric generator, the attainable efficiency is generally as great. Recently, concern has developed relating to the potential carcinogenic aspects of diesel exhaust. Future utilization of stationary diesel generators may well depend on diesel emission control standards. The cost of diesel derived electric energy is somewhat higher than that from a conventional steam-electric plant. This is due to the relatively high operating cost (per kwh electric energy) of a diesel generator installation. DOD experience indicates diesel derived electric energy is at least twice as expensive as that purchased from an electric utility. Even so, for selected applications, diesel generators are very appropriate.

Current fluidized-bed combustion efforts are largely in the research, development, and demonstration stages. Some manufacturers have recently begun to advertise the availability of atmospheric commercial/industrial scale units. The attainable boiler efficiency is limited by the same general loss components as for a conventional boiler. Boiler efficiency values equal to those attainable by conventional boilers will depend on the ability to achieve substantially complete carbon burn-up. The environmental aspects of a fluidized-bed boiler are similar to that of an equivalent capacity conventional boiler with flue gas desulfurization (FGD) burning the same coal. A major difference is the relatively low NO_x emission and the amount and nature of the spent bed material as compared to the effluent from a FGD system. For fluidized-bed combustion with the same SO_x removal, almost three times as much limestone is required. Spent bed material from a fluidized-bed boiler contains appreciable CaO (i.e., quicklime) that may present handling and disposal problems. Hopefully, commercial uses will be found for the spent bed material. In the near term, fluidized-bed boilers are projected to compete with industrial/commercial scale conventional boilers with SO_x emission control. Such units when developed would permit coal to be burned more conveniently at such locations as schools, hospitals, shopping centers, office buildings, small industrial parks, etc.

There are many gas turbine-steam combined-cycle power plants currently in operation which achieve overall efficiencies around 40 percent. However, these systems currently rely upon gas or oil the price and future availability of which have become of serious concern. Therefore, there is major emphasis on making today's turbines run more efficiently on these scarce fuels and to develop improved turbines that will operate efficiently on the synthetic fuels that will one day replace oil and natural gas. In addition to improved efficiency, such combined-cycle power plants utilizing gas-turbine and steam-turbine technology have a number of other key features which could make them particularly appealing to the utility industry. Besides very fast start-up capabilities, these features include relatively low capital investment per kilowatt of electric generation, relatively low operating costs, and the capability for use as a base-load or peaking power plant. Another potentially promising aspect of the combined-cycle power plant is its projected ability to use low-energy gas from coal. The environmental implications of this are significant. Since such low-Btu gas can be clean burning, much of the environmental control problems and expense associated with conventional coal-fired steam generating plants would be avoided. A variation of the combined gas turbine and steam-turbine system features the direct combustion of coal in a pressurized fluidized-bed (PFB). Although internal particulate control is still required, the PFB offers the potential for direct combustion of high-sulfur coal without stack gas cleanup while achieving an overall coal pile-to-bus bar plant efficiency of approximately 40 percent.

The low/medium-Btu gasification of coal is essentially an existing technology. In fact, gas manufactured from coal was first produced in the eighteenth century. Currently, low/medium-Btu coal gasifiers are in use in Europe, South Africa, and to a very limited extent, in the United States. Coal can be gasified by any of several processes: synthesis, pyrolysis, hydrogasification. In synthesis, coal or char is reacted with steam and oxygen or air and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In the process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form methane. Pipeline gas is produced by upgrading a medium-Btu gas. Environmental problems common to coal associated energy generating systems will generally also apply to coal gasification facilities. Additional adverse environmental aspects of proven and pilot plant processes are difficult to assess because of the very limited data available from such operations. The conversion efficiency as based on total energy input, is somewhat process and site specific and is estimated to be in the 70 to 80 percent range including raw gas cleanup. The value without gas cleanup (i.e., raw hot gas output) is estimated to be as high as 90+ percent when the sensible heat of the gas is included. Since this is basically a developed technology, over the foreseeable future, efficiencies are not expected to improve significantly. The cost is currently estimated at $2.50 to $4.00 per million Btu.

The chemically active fluid bed (CAFB) process uses a shallow fluidized-bed of lime or lime-like material to produce a clean, hot gaseous fuel from high sulfur feedstock (e.g., residual oil). Solid fuel feedstocks such as coal are also feasible. The initial CAFB pilot unit (2.39 Mw) was developed by the Esso Research Centre in Abingdon, England. A 10 Mw demonstration plant has subsequently been constructed by Foster Wheeler at the La Palma Power Station (Central Power and Light Company) in San Benito, Texas. EPA is sponsoring the demonstration of this technology. Environmental data are very limited. Principal environmental concerns relate to the size of the particles in the product gas stream, the vanadium (bound in a mixture of oxides) emission level, and the disposal of spent, sulfided limestone. The solid waste disposal problem appears to be the major environmental concern. Since all activities are R&D, no actual full scale performance data are available. In this regard, the total gasification efficiency is estimated to be approximately 87 percent. Similarly, economic values are also projections. EPA estimates that a retrofit CAFB plant to fuel a 500 Mwe plant would cost $172 per kw of installed capacity; the operating cost is estimated at 2-3 mills per kwh (1977 dollars).

Coal liquefaction provides the means to produce liquid fuels from coal. In indirect liquefaction, the coal is gasified to make a synthesis gas and then passed over a catalyst to produce alcohols (methanol) or paraffinic hydrocarbons. In direct liquefaction the coal is liquefied without a gasification intermediate step. Specific processes are generally directed toward converting coal to liquid fuels with minimal production of gases and organic solid residues. The liquid products that are produced vary with the type of process and the rank of coal that is utilized. Research and development of coal liquefaction has been underway for many years. The first practical uses of coal-derived liquid fuels were about 1790 when the fuels were used for experimental lighting, heating, and cooking. During World War II, Germany produced liquid fuels from coal in industrial amounts (45 million bbl/year). Since then, coal liquefaction plants have been constructed in a number of countries but currently only South Africa is producing liquids from coal. Commercial demonstration of coal liquefaction has never been accomplished in the United States. Current U. S. activities are limited to research and development and pilot plant programs. Environmental problems common to fossil energy facilities will also apply to coal liquefaction facilities. Liquefaction processes present some unique problems such as the need for the characterization of materials with carcinogenic effects, characterization and treatment of wastes, fugitive emissions, and effluents and the disposal of sludges and solid wastes. These problems are generally common to all liquefaction processes, however, since no large scale plants are in operation in the U. S., the only available data on emissions and effluents are estimated from pilot plant operations and cannot be completely quantified for a commercial operation. Projected efficiencies for coal liquefaction facilities are in the 55 to 70 percent range. Accurate values for coal conversion efficiencies are difficult to estimate and thus an exact value cannot be given until commercial demonstration takes place. Estimated costs for indirect coal liquefaction plants are in the $7-10 per million Btu range (1980 dollars). Generally, the estimated cost for direct coal liquefaction plants is less than for indirect liquefaction.

High-Btu gasification of coal can be accomplished by any of several processes: synthesis, pyrolysis, or hydrogasification. In synthesis, coal or char is reacted with steam and oxygen and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In the process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form methane. To produce a pipeline quality gas, medium-Btu gas (e.g., from hydrogasification) is cleaned and further treated. This further treatment could include a shift conversion to obtain the proper carbon monoxide to hydrogen ratio followed by a second purification process, followed by a methanation process. To an extent, environmental concerns common to coal-fired boiler facilities will also generally apply to coal gasification facilities. Additional unique adverse environmental impacts are difficult to estimate. No commercial plants are in operation anywhere in the world and assessments must be based on limited information from pilot plants. In addition, information from a pilot plant may not be representative of a commercial operation. Projected overall energy efficiencies for coal gasification have been estimated to be approximately 75 percent. The estimated at gate costs of high-Btu gas produced by a gasification plant are \$4 to \$6 per million Btu (1977 dollars).

Oil shale resources can be processed either by conventional mining followed by surface processing or by in situ (in place) processing. In situ processing can be accomplished by either true or modified in situ methods to extract oil from shale. Oil shale resources in the United States are estimated to exceed two trillion barrels of petroleum and of the total, 25 to 35 percent is presently projected as commercial. Shale oil has been produced commercially at various time intervals in eleven countries since the initiation of shale oil operations in France in 1838. In Canada and the Eastern United States, a very small industry was operating around 1860, but disappeared when petroleum became plentiful. Currently, the only commercial production is in Russia (Estonia) and China with a combined production of approximately 150,000 barrels per day. The conventional process (conventional mining and surface retorting) to produce a crude is composed of four major steps: mining the shale; crushing it to the proper size for the retort vessel; retorting the shale to release the oil; and refining the oil to a high-quality product. True in situ processes involve fracturing the shale bed via vertical well bores to create permeability without mining or removal of material followed by underground retorting. Retorting can also be done via well bores utilizing natural permeability where it may exist. The modified in situ process involves mining or removing by other means (such as leaching or underreaming) up to 40 percent of the shale (i.e., in the retorting section) in order to increase the void volume and allow rubblization before retorting. In modified in situ, the mined shale can be surface retorted. Considerable environmental questions are associated with oil shale processing and until these uncertainties as well as the demonstration of an economically acceptable commercial scale viable technology are resolved, future development of a viable oil shale industry is uncertain.

The fuel cell, by converting chemical energy directly to electricity, can efficiently use fuels without an intermediate mechanical step. Fuel cell power plants offer many attractive characteristics such as modular construction, low environmental emissions, high efficiency and rapid response to load demand fluctuations. Because of the modular construction, fuel cells are easily transported and installation times and costs reduced. The fuel cell concept itself is not new: such cells have already provided power for moon landings and, between 1971 and 1973, provided electric power to 50 apartment houses, commercial establishments, and small industrial buildings. What is new is an effort to capitalize on the fuel cell's inherent flexibility, safety, and efficiency by putting together a generator system that can use a variety of fuels to meet today's utility-scale power need economically. Environmental considerations like low water requirements, limited emissions, and quiet operation help make fuel cell plants an attractive power option. Whereas fossil fuel and nuclear plants require large quantities of water for cooling, fuel cells generate less heat and can be air-cooled by low speed fans. Because fuel cells can use a variety of hydrocarbon fuels, they share with conventional generating processes the environmental problems currently associated with extracting and processing fossil fuels. The required hydrogen for the fuel cell power section can be derived by gasifying coal. In such a case the coal gasifier would be an integral part of the fuel cell power plant. The Energy Conversion Alternatives Study (ECAS) team estimated an overall efficiency of 50 percent for its conceptual molten carbonate fuel cell power plant. Although still in the prototype stage, the fuel cell offers a means to produce electricity efficiently on both small and large scales. These systems could be used to complement existing facilities or supply new generating capacity where environmental considerations restrict conventional combustion plants.

Magnetohydrodynamics (MHD) is a potential energy alternative in which electricity is generated directly from thermal energy, thus eliminating the conversion step of thermal to mechanical energy encountered in conventional steam-electric generators. However, due to the nature of the process, it would be inefficient to apply MHD by itself to the large scale generation of electricity. Therefore, its eventual implementation is being planned around combining MHD with a conventional steam plant to make use of the waste heat from the MHD generator. The efficiency of such a combined MHD/steam plant is predicted to be about 50 percent as compared to 38 percent projected for conventional coal-fired power plants with flue gas desulfurization (FGD) systems. Unlike rotating machines, much of this increase in efficiency is attributed to the fact that all the rigid structures in MHD generators are stationary, thus permitting operation at elevated temperatures approaching 5000°F. These temperatures are much higher than even the most advanced contemporary plants, resulting in much higher efficiencies through the entire thermal cycle than are attainable in such conventional plants. Although much work remains before the widespread application of the magnetohydrodynamic energy conversion process to electric utility power generation, there is experimental evidence that MHD can significantly improve overall power plant efficiencies. Another promising aspect of this technology is the ability to remove, during the process, pollutants such as SO_x, NO_x, and particulates generated in the combustion of coal, thereby eliminating the need for external flue gas scrubbing to meet environmental standards.

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INTRODUCTION

In an era of increasing fuel scarcity and environmental concern, it is necessary to consider the implications associated with the various options for electric power generation, steam generation, and the conversion of fossil energy values into alternative forms. This report provides a review of 13 fossil fuel associated processes that currently, or in the future, could be used for generating energy or converting fuel from one form to another. The processes covered are either on-line or are in various stages of research and development. These processes are those at the forefront of current capabilities or are believed to hold significant future promise. The 13 processes are:

1. Conventional Boiler (with steam turbine)
2. Diesel Generator
3. Fluidized-Bed
4. Combined Cycle
5. Low/Medium-Btu Gasification
6. Chemically Active Fluid Bed (CAFB)
7. Indirect Coal Liquefaction
8. High-Btu Gasification
9. Surface Oil Shale Processing
10. In Situ Oil Shale Processing
11. Direct Coal Liquefaction
12. Fuel Cells
13. Magnetohydrodynamics (MHD)

The ordering of the processes roughly corresponds to our estimate of current and future significant commercial utilization. To assure consistency and also provide an aid for comparative purposes, a uniform format is used for each technology writeup. The major sections are as follows:

- Overview
- Process Description
- Applications
- Environmental Considerations
- Performance
- Economics

The Overview section provides a general summary of the particular process. The Process Description section describes the process/technology from both a theoretical and operational viewpoint. Included in the Detail portion of the Process Description sections are energy balances for the individual energy conversion or generation processes. The Applications section covers current (where applicable) and projected with emphasis on utility applications. The Environmental Considerations section is subdivided into identified pollutants and regulatory impacts. As appropriate, the emphasis is on utility applications. The ability of each technology to comply with the current New Source Performance Standards

(NSPS) is identified as appropriate. Since the composition of the emissions and effluents associated with many of the new and developing technologies have yet to be fully characterized, only the major identified emissions and effluents are emphasized. The Performance section and the Economics section cover current and projected values. When there is no operating experience, projections are provided.

Table 1 lists the thirteen addressed technologies including the input fuel(s) and the specific output(s) of each. As an example, the atmospheric fluidized-bed combustor provides steam and the chemically active fluid bed, (low-Btu) gas. For each technology, the current status (e.g., commercial) is given along with an estimate of the current (1980) and projected (1990-2000) efficiency. The efficiencies as expressed are based on accepted definitions as related to the specific process and output (e.g., diesel generator; electrical energy). It must be emphasized that the efficiency values are for the specific process and not necessarily a value to produce electricity. For example, the chemically active fluid bed is projected to have a process efficiency of 87%. However, the overall efficiency to produce electricity (via steam generator) would be 31%. It should be noted that for all processes a range of efficiency values are to be expected and the provided values are typical efficiency values for each individual technology.

The presented material is based on information obtained from available technical literature as well as from government and industry sources. Every effort was made to include the most timely and relevant information. A customized on-line data search of the National Technical Information Service (NTIS) data base containing in excess of 500,000 reports was performed and appropriate reports obtained. This information was reviewed as to its relevance to the 13 processes and used as appropriate for report development.

This report is intended to give the reader a general understanding and appreciation for the relative environmental, operational, and economic characteristics of the 13 processes addressed. Should further detail be required beyond these limited assessments, the reader is referred to the list of references appearing at the end of each technology section. Current and projected emission levels, economic data, and other values quoted for each of the processes were obtained from the reference materials. The reader is cautioned that these values are considered to be generally representative of the particular processes under given conditions and are not to be construed as absolute. These values will vary with the specific installation, system configurations, heat content of fuel, or any one or combination of a myriad of other variables. In the case of commercially available technologies, the data presented can be traced to actual achieved performance. When dealing with the new or developing technologies still undergoing intensive research, performance data have been projected by a number of researchers based on conceptual models, laboratory experiments, or, in some cases, pilot plant operations. Needless to say, such data must be considered rough engineering estimates and evaluated as such by the reader.

Table 1

Summary of Representative Current and Projected Efficiencies of the Thirteen Energy Technologies

Technology	Status	Input Fuel(s)	Principal Output(s)	Process Efficiency (%) Current (1980)	Process Efficiency (%) Projected (1990's)	Comments
1. Conventional Steam Electric Plant	Commercial	Coal	Electricity	34	38	Values for plants with flue gas desulfurization (FGD). Without FGD, values are 35.4 and 39.5 respectively.
2. Diesel Generator	Commercial	Diesel Oil	Electricity	33	36	Established technology.
3. a) Atmospheric Fluidized-Bed Combustion	Commercial and R&D	Coal	Steam	(a)	85	Insufficient operating history to establish efficiency value.
b) Pressurized Fluidized-Bed Combustion	R&D	Coal	Electricity	(a)	39	A combined cycle concept.
4. Combined Cycle	Commercial and R&D	Gas or Oil (or Coal)	Electricity	38	43	Currently fueled by gas or oil. Projected efficiency is based on an integrated coal fed gasifier.
5. a) Low-Btu Gasification	Commercial and R&D	Coal	Low-Btu Gas	86	90	The efficiency values include the sensible heat component and export power.
b) Medium-Btu Gasification	Commercial and R&D	Coal	Medium-Btu Gas	80	83	The efficiency values include the sensible heat component.
6. Chemically Active Fluid Bed (CAFB)	R&D	Heavy Residual Oil or Coal	Gas	(a)	87(b)	The efficiency value includes the sensible heat component.

(a) No U.S. commercial plants in existence or with an operating history

(b) Projected overall efficiency to produce electricity (via steam generator) is 31 percent

Table 1 (Cont'd)

Summary of Representative Current and Projected Efficiencies of the Thirteen Energy Technologies

Technology	Status	Input Fuel(s)	Principal Output(s)	Process Efficiency (%) Current (1980)	Process Efficiency (%) Projected (1990's)	Comments
7. Indirect Coal Liquefaction	Commercial and R&D	Coal	Hydrocarbon Products	(a)	58	Commercial in South Africa, all U.S. activities R&D. Efficiency value very dependent on product mix.
8. High-Btu Gasification	R&D	Coal	High-Btu Gas	(a)	75	The efficiency value includes credit for export electric power.
9. Surface Oil Shale Processing	R&D	Oil Shale	Oil and Gas	(a)	68	Substantial variation in obtainable value depending on very site specific conditions.
10. Modified In Situ Oil Shale Processing	R&D	Oil Shale	Oil and Gas	(a)	68	Substantial variation in obtainable value depending on very site specific conditions.
11. Direct Coal Liquefaction	R&D	Coal	Hydrocarbon Products	(a)	63	Value for EDS process. Includes credit for by-products.
12. Fuel Cells	R&D	Fossil Fuel (e.g., gas obtained from coal)	Electricity	(a)	50	The efficiency value is for a coal fueled (via gasifier) plant with a steam-turbine bottoming cycle.
13. Magnetohydrodynamics (MHD)	R&D	Coal	Electricity	(a)	48	The efficiency value is for an open-cycle MHD/ steam plant.

(a) No U.S. commercial plants in existence or with an operating history

TECHNOLOGY ASSESSMENTS

1. Conventional Coal-Fired Steam-Electric Power Plant

1.1 Overview

The conventional boiler steam-electric plant (also referred to as boiler-turbine plant) is by far the most employed means of generating electric utility produced electric energy in the United States. In 1978, over 72 percent of electric utility produced electric energy was from coal, oil or gas-fired boiler steam-electric plants. Of the total fossil fuel derived utility electric energy in 1978, over 61 percent was from coal firing.

Recent and projected electric utility supplied electric energy mix as based on reference 1 is provided in Table 2. Undoubtedly, steam-electric plants will be the backbone of the U.S. electric utility industry in the foreseeable future.

Table 2

Projected Generation Mix
(Based on kilowatt-hours)

Type Generation	1976 Actual Percent	1981 Percent	1986 Percent
Coal	46.3	47.7	47.7
Oil	15.7	17.7	14.6
Gas	14.4	6.6	2.8
Fossil Fuel Total	76.4	72.0	65.1
Nuclear	9.4	19.0	27.8
Hydro	13.9	8.5	6.5
Other	0.3	0.5	0.6
Total	100.0	100.0	100.0

The current efficiency of on-line steam-electric plants range from approximately 31 to 38 percent. The prospect for the foreseeable future is that newer plants will have efficiency values below 40 percent. It is unlikely that truly operational efficiency values in excess of 40 percent from conventional plants will be realized within the next 15 to 20 years.

In the absence of pollution control measures, coal-fired steam-electric plants would provide very substantial undesirable environmental impacts. However, the current environmental control state-of-the-art and resulting control measures are capable of substantially mitigating currently identified undesirable pollution and other environmental effects. Continuing environmental control activities are expected to provide the means to control potential overall undesirable effects resulting from increasing use of coal to fire steam-electric plants.

1.2 Process Description

Concept

The conventional boiler steam-electric plant basically consists of a fossil fuel fired boiler to generate steam that in turn drives a turbine generator. In addition, a full plant contains many other associated elements. These include: (1) coal handling components, (2) ash handling units, (3) a steam condenser with associated water cooling provisions (e.g., tower, pond), (4) plant water treatment elements, and (5) often a stack gas cleanup system with associated reagent and effluent handling elements. A typical basic diagram of a conventional system is provided in Figure 1.

Heat for the production of steam is obtained from the combustion of a fuel in a furnace. The energy released by the combustion of fuel is absorbed by the operating medium (usually water and its vapors) in a boiler. The boiler is a closed vessel in which water is confined and heated, steam is generated, steam is superheated, or any combination thereof, usually under pressure by the application of heat from combustion of fuels. In practice, the boiler is generally a combination of tubing with one or more cylinders called drums. Steam produced in the boiler drives a turbine. The shaft of the turbine assembly is coupled to an electric generator.

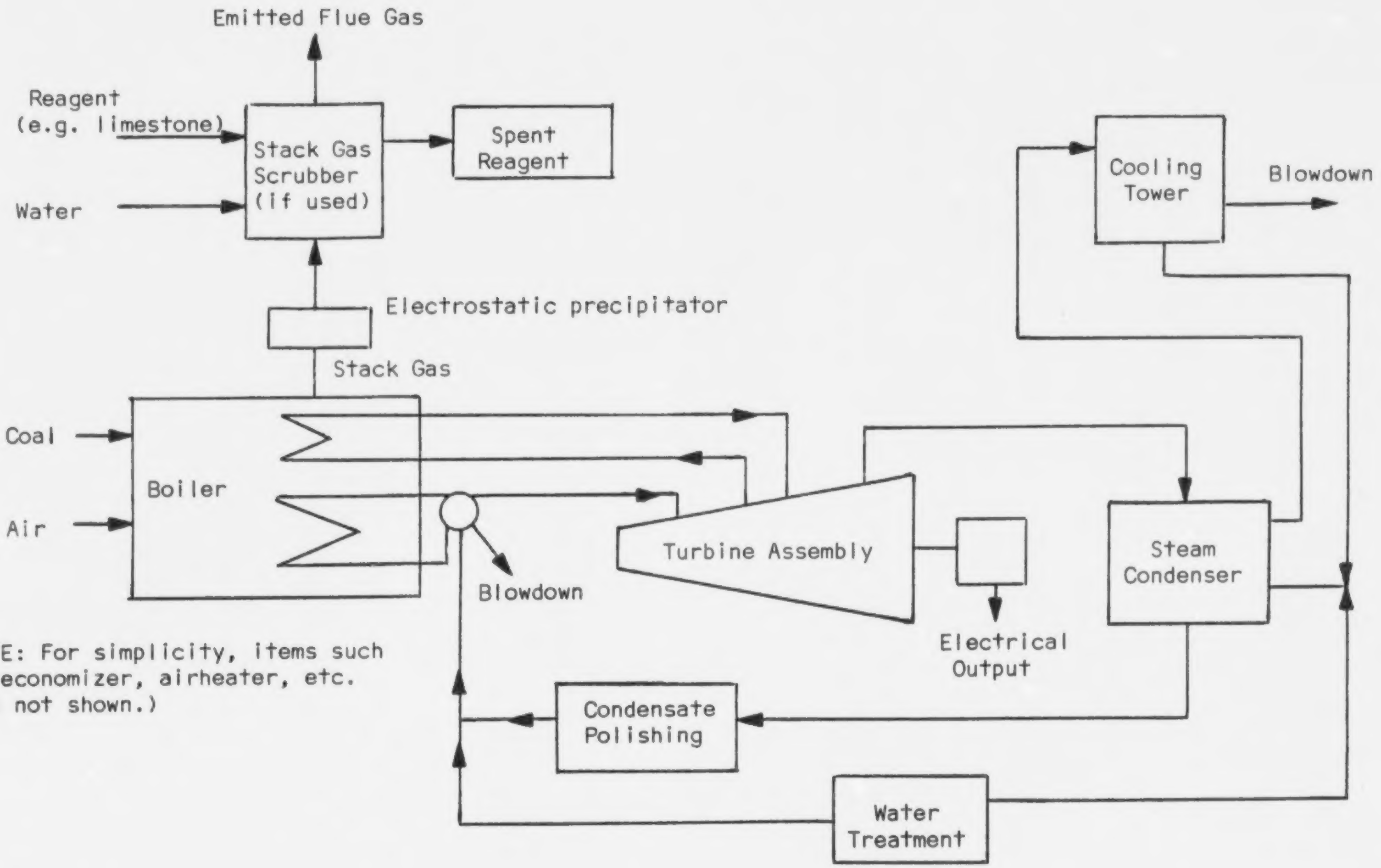
Detail

For the fuel combustion process to adequately take place in a furnace, it is necessary to:

1. Introduce fuel and air for combustion,
2. Burn the fuel,
3. Remove the products of combustion and refuse remaining after combustion.

The five requirements for perfect combustion are:

1. Proper proportions of fuel and air,
2. Adequate mixing of fuel and air,
3. Sufficient boiler surface heat transfer area,


Emitted Flue Gas
Reagent
(e.g. limestone)
Water
Stack Gas
Scrubber
(if used)
Spent
Reagent
Electrostatic precipitator
Stack Gas
Coal
Air
Boiler
Blowdown
Turbine Assembly
Electrical
Output
Cooling
Tower
Blowdown
Steam
Condenser
Condensate
Polishing
Water
Treatment

(NOTE: For simplicity, items such as economizer, airheater, etc. are not shown.)

Figure 1

Conventional Steam-Electric Plant

4. Sufficient combustion temperatures, and
5. Adequate fuel residence time to allow for complete combustion.

The efficiency of a steam-electric power plant is defined as the ratio of electrical energy output to the total plant energy input. Overall plant efficiency is determined by many factors including boiler efficiency, turbine performance in relation to supplied energy, generator efficiency, plant losses, auxiliary power requirements, etc.

Boiler efficiency is defined as the ratio of heat absorbed by the water and steam to the heat in fuel fired. In this regard, the state-of-the-art in boiler plant design and manufacture is well advanced. Modern utility boiler plants are generally very efficient with factors affecting losses in efficiency well understood.

For modern utility boilers, boiler efficiencies in the range of 85 to 90 percent are representative of the current state-of-the-art. The major components with their representative loss values are the following:

1. Heating excess combustion air (≈0.1-0.3%)
2. Incomplete fuel combustion (less than 1.0%)
3. Heating of moisture in coal and air (4-10%)
4. Losses associated with energy in flue gas (4-6%).

In a steam-electric power plant, the steam from the boiler, as previously indicated, is fed to drive a steam turbine. The steam turbine is a heat engine that takes energy from a high temperature, high pressure steam, converts the extracted heat energy to mechanical energy, and rejects unusable waste heat at a lower temperature and pressure. The discharged steam is condensed to water in a condenser. This same water is then pumped back into the boiler to be reheated and start the cycle over again. The heat from the condenser is rejected to the environment usually via a cooling tower or cool body of water.

In actual practice, the turbine assembly is composed of several units. Typically, the spent steam output from the first or high-pressure turbine is reheated and fed to the second or intermediate turbine. The spent steam output of the second turbine then feeds the low pressure turbine. After the turbine, the discharged steam is converted to water by the condenser and is continuously directed back to the boiler (often after processing to remove undesirable contaminants) to continue the cycle. During the cycle, some of the boiler working medium (steam and water) is lost or possibly purposely rejected to dispose of undesirable boiler water constituents. Makeup feedwater is processed to be more acceptable to the boiler and fed to the boiler to compensate for system working medium losses.

According to the second law of thermodynamics, a heat engine such as the steam turbine cannot convert all of the transferred heat into mechanical energy. That is, given a source of heat coupled with a heat/work cycle, only a portion of the heat can be converted to work and the remainder is rejected as heat to a sink such as the atmosphere. The Carnot cycle is a theoretical concept which depicts a heat engine operating within the second law of thermodynamics. This cycle has no real counterpart in practice but is useful as a standard in evaluating the performance of actual heat engines.

The Rankine cycle is a reversible cycle, similar to the Carnot cycle. As compared to the Carnot cycle, the Rankine cycle more nearly approximates steam turbine energy system efficiencies. If a Rankine cycle is closed in the sense that the same working fluid is used in a continuous fashion, it is termed a condensing cycle. There are two modifications as to boiler/turbine interconnect that can improve the thermal efficiency of the Rankine cycle (and the steam turbine). These are:

1. Reheat - This involves a process where a portion of the steam that has partially expanded in the turbine is reheated in the boiler and then returned to the turbine to complete the expansion process. The output from one turbine section can be reheated in a boiler and then returned to a second turbine section.

2. Regeneration - This involves extracting a portion of the steam from the turbine after (only) partial expansion and transferring heat energy to boiler return water prior to entering the boiler.

The Carnot cycle efficiency is a theoretical value that cannot be achieved in practice but can serve as a measure of performance for actual cycles. This cycle offers maximum thermal efficiency attainable between any given temperature of heat source and sink and depends only on these two temperatures. The Carnot efficiency is given by:

$$E = \frac{T_1 - T_2}{T_1} = 1 - \frac{T_2}{T_1}$$

where:

E = thermal efficiency of heat to work conversion (decimal value)

T_1 = absolute temperature of heat source, R

T_2 = absolute temperature of heat sink, R

The equations show that the thermal efficiency is improved by increasing the temperature of the heat source and decreasing the temperature of the heat sink.

A turbine generally has a maximum inlet steam temperature of approximately 1000°F (1460 R) and a minimum sink temperature of 70°F (530 R). This corresponds to a Carnot (i.e., theoretical) conversion efficiency of 64 percent.

In actual practice, the value is considerably less for a number of reasons. The actual turbine cycle efficiency does not approach that of the Carnot cycle. In addition, there are a number of losses which include but are not limited to the following:

1. Residual velocity loss. The steam leaving the turbine also carries with it residual velocity loss which dissipates into increased enthalpy of the steam entering the condenser,
2. Steam leakage losses at shaft glands, or packing, between stages,
3. Nozzle losses due to friction and turbulence,
4. Blade losses caused by friction and turbulence,
5. Rotational losses caused by the friction between the blades and rotating parts of the turbine turning in the steam,
6. Bearing and external losses,
7. Radiation loss (usually relatively negligible).

In addition, when considering the entire steam electric system, there are generator losses which generally are relatively minor. The efficiency of the electrical generator (which varies with load) is generally in excess of 98 percent.

A reasonable heat balance (Table 3) for a plant with full FGD and an overall plant efficiency (including the FGD system) of 35 percent (nominal) follows. The tabulation is based on a 500 MWe plant and is provided both in terms of Btu flow per hour and percent of Btu flow. The values are consistent with the above discussion and represent a plant within the size and efficiency ranges of utility plants currently in service.

Diagrammatically, this can be illustrated by the heat flow diagram, Figure 2. This diagram indicates the energy disposition on a percentage of the total input basis and is consistent with Table 3.

Table 3

Heat Balance for 500 MWe Conventional Coal-Fired Steam-Electric Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Electrical Energy Output	1,706.10	35.0
Furnace Losses		
Heating excess combustion air	9.75	0.2
Incomplete fuel combustion	39.00	0.8
Heating moisture in coal and air	243.70	5.0
Energy in flue gas	243.70	5.0
Miscellaneous (heat loss, etc.)	24.40	0.5
Heat Rejected		
Heat rejected to cooling tower and otherwise lost (e.g., through boiler blowdown)	2,456.78	50.4
Energy Consumed (Auxiliaries and others)		
FGD system	70.70	1.45
Coal preparation	21.94	0.45
Cooling tower pumps and fans	19.50	0.40
Other (electrostatic precipitators, system fans, etc.)	39.00	0.80
Total Energy Input	4,874.57	100.0

Based on coal with 11,500 Btu/lb, 3 percent sulfur by weight.

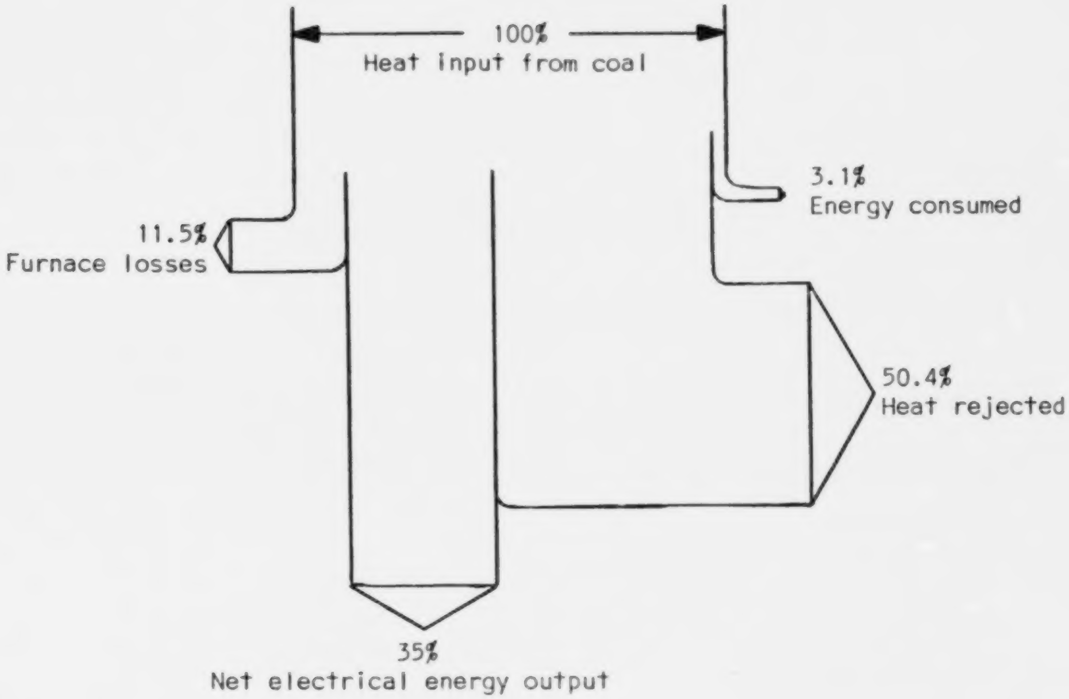

100%
Heat input from coal
3.1%
Energy consumed
11.5%
Furnace losses
50.4%
Heat rejected
35%
Net electrical energy output

Figure 2

Heat Flow Diagram for Conventional Coal Fired Steam Electric Plant

1.3 Applications

Current

In 1978, coal supplied approximately 44 percent of the total input energy for utility electrical power generation in the United States (2). According to Reference 3, there was a 6.9 percent increase in Btu's supplied by coal to electric utilities for 1977 as compared to 1976. For 1979, coal was estimated to fuel approximately 1,075 X 10^9 kwh out of a total of 2,248 X 10^9 or 47.8 percent of the total (2). The energy supplied by this coal would be used to fuel conventional steam-electric plants.

During 1978, 61.2 percent of utility electric power produced by fossil-fired plants was from burning coal. This represents 974.3 X 10^9 kwh out of a total fossil fuel level of 1,592 X 10^9 kwh. During the same period, nuclear accounted for only 255 X 10^9 kwh of electrical energy. In the United States, coal provides for substantially more electric power than any other fuel (3).

Projected

The 1979 issue of the National Coal Association publication entitled "Steam Electric Plant Factors" (3) has identified 269 coal fired steam-electric plants projected to come on stream by the end of 1988. These 269 plants have a capacity of 140,887 MW. In contrast, only 11 oil fired plants with a total capacity of 6,722 MW have been identified for the same period.

All indications are that the U.S. electric power industry will become increasingly dependent on coal. In the foreseeable future, it is expected that essentially all new coal fueled utility plants will be the conventional boiler-turbine variety covered by this report.

1.4 Environmental Considerations

Emissions from power plants can be classified as continuous, scheduled intermittent, and unscheduled intermittent. Continuous emissions include pollutants that are contained in the flue gas discharged from the furnace stack. Scheduled intermittent emissions include discharge of limestone and ash to storage piles, and aqueous wastes from cleaning equipment. Unscheduled intermittent emissions include transients due to operating upsets, fugitive dust from coal, and storm run-off. For each operating or projected power plant, all of these pollution sources must be thoroughly considered and adequately controlled. Pollution control methods may vary and will depend to a considerable extent on the specific plant design and operating situation. While some variability certainly exists, this evaluation of the potential environmental intrusion of a modern power plant using a conventional furnace provides a framework to guide the evaluation of emissions from fossil fuel fired power systems. It also represents a base case against which new energy conversion systems can be compared, to see in what respects they are better or worse than present technology. The provided environmental material was derived in whole or part from reference 4. References contained in reference 4 are also provided herein.

Identified Pollutants

Areas of environmental concern are summarized in Table 4. In the following detailed discussion, emissions to the air will be discussed first, in the order of process flow, followed by a simiiar discussion of solids and liquid effluents, and then trace elements.

Table 4

Emissions and Effluents from Conventional Power Plants

Emissions to Atmosphere	Potential Concerns
Wind action on coal storage and handling	Dust, fire, odors
Wind action on limestone and waste	Dust
Waste vapor from grinding	Dust, H_2S
Cleaned flue gas	NO_x, plume dispersion, dust, SO_x, POM*
Vacuum pump on steam condenser	Minor
Air and mist from cooling tower	Plume, mist deposition, trace chemicals
Possible fugitive dust from area	Dust nuisance
Transients due to upsets, cleaning, etc.	Dust, smoke, fumes
Potential noise and odors	Machinery, maintenance
Effluents - Liquids and Solids	
Rain runoff - coal, limestone, and waste areas	Suspended and dissolved matter
Ash Slurry	Groundwater contamination
Slurry of waste from stack gas cleanup	Groundwater contamination and land use
Sludge and chemicals from water treating	Minor
Trace Elements	
Leaching associated with disposal of ash and limestone waste	Soluble toxic elements
Fate of volatile toxic elements in coal feed	Contamination of local air and water
Emissions as gas and PM and POM with stack gas	Health hazard

* = Polynuclear Organic Material

Air Emissions

The first area to consider is the coal preparation area, primarily coal storage and grinding. Wind action on the coal pile can cause a dust nuisance especially during loading and unloading operations.

The grinding process, prior to firing in a pulverized coal fired boiler, reduces the coal to smaller than 200 mesh. Moisture laden grinding effluent gas from drying may contain sulfur compounds, combustibles, and other trace components. Depending on its composition, the stream may need to be either scrubbed or incinerated prior to venting.

The precautions used to prepare the stack gas scrubbing reagent should be similar to those of coal, since the scrubber reagent (e.g., limestone) is often stored, ground, and used in a manner comparable to coal.

Ground coal is fed to the furnace where it is essentially completely burned. The ash residue (bottom ash) is withdrawn and quenched with water, care being required to see that vapors and fumes from quenching are collected and returned to the system rather than becoming an effluent to the air. Ash is handled as a slurry to prevent dusting.

Flue gases from the furnace are a major environmental concern since they contain many pollutants including SO_x, NO_x, polynuclear organic matter (POM), trace elements, etc. At present, there is no fully accepted way to remove NO_x from flue gas, but NO_x can be controlled by modifying combustion conditions to minimize its formation. Flue gas recirculation staged combustion, and reduction of excess air are methods that have been effectively demonstrated on full size equipment (5). These methods tend to decrease flame temperature, and/or the availability of oxygen. Currently the U.S. Environmental Protection Agency through its laboratory in North Carolina is pursuing a substantial program addressing NO_x reduction by burner/combustion modification techniques. Limestone scrubbing is used primarily to remove sulfur oxides but can also be effective in removing particulates, associated trace elements, and other contaminants. Electrostatic precipitators remove most of the dust ahead of the limestone scrubber. Electric precipitators are very effective in removing particles greater than a micron. Submicron particles, on the other hand, are not removed efficiently by these precipitators.

Adjusting the data presented by Crawford et al. (5) for an 800 MWe power plant using a tangentially fired furnace operating at 24.2 Mpa/811 K with Black Mesa Subbituminous coal which contains 1.4% N (moisture free) for the specific example in this base case, potential emissions are compared with Federal standards in Table 5, in order to show the degree of removal or cleanup required.

Table 5

Base Case Flue Gas Pollutants

	In Raw Gas g/J	New Source Performance Standard g/J	% Removal Required
SO_x (as SO_2)	3.10	0.31*	90.0
NO_x (as NO_2)	0.28	0.215	23.0
Particulates	3.84	0.013	99.66
CO	0.02	None	None

* See NSPS for SO_x emission criteria as a function of coal sulfur content.

In a stack scrubber, generally some water is evaporated to cool the gas by adiabatic humidification. The scrubbed gases are then released to the atmosphere. The scrubbing system should be designed to minimize and control mist and spray carryover. It is important to control and minimize entrainment and loss of the scrubbing liquid in the vent gas, since it may cause objectionable residues, deposits and other problems.

As more information is obtained, other pollutants in the flue gas may become of concern. For example, nitrates, HCN, sulfates, and organic matter are areas now being examined. Also, it is known that chlorides in the coal are volatilized during combustion, and can leave in the flue gases as HCl. In many operating power plants, the HCl formed is presumably released to the air, but with limestone scrubbing, it will be removed by reacting with the limestone to form soluble $CaCl_2$.

Periodic cleaning of furnace equipment is required and precautions are needed to avoid emissions to the air at such times. One method of on-stream cleaning of heat transfer surfaces is called "soot blowing," using high velocity jets of steam to dislodge deposits. Most of the additional dust load will be recovered in the electrostatic precipitator and scrubber but if the system is overloaded, there can be serious emission of pollutants. The deposits are made up of fine particles, which will be high in volatile trace elements according to indications from related studies (6). Equipment cleaning at shutdown or during turnaround can also cause dust nuisances, or even a hazard in the case of deposits of toxic materials.

The final air emission consideration is the cooling tower. The air flow through it is by far the largest stream in a plant, and its contamination is therefore a major concern. Fortunately, it appears that it will be clean and not subject to contamination. The cooling water in a power plant is used almost exclusively for condensing steam under vacuum, and very little is exchanged with lubricating oil or scrubbing liquid where leaks could cause contamination (7).

Solid and Liquid Effluents

The first effluent of solids and liquids covered are those from the coal and limestone storage piles and handling area. Here, rain runoff will contain suspended solids and may also contain soluble sulfur and iron compounds. The coal pile is subject to oxidation and weathering, with conditions similar to those associated with acid mine water. As one precaution, curbing should enclose the storage pile and coal preparation area, so that runoff can be segregated and sent to a storm pond for settling. The water can then be treated prior to disposal or treated and used for makeup.

The next consideration is ash disposal from the furnace. The ash is slurried with water for handling and will go to an ash pond in some cases for settling, so that the water can be recycled. Ash is then periodically removed from the pond bottom for offsite disposal as landfill, construction raw material , or for some other application. Ash disposal poses serious problems with regard to dusting when it dries out, and in the presence of water it can cause problems from possible leaching of sulfur, trace elements and soluble salts. Therefore, the ash pond may have to be lined, and the extent of leaching determined and controlled for any specific situation. Some preliminary studies have been made in this area (8), but much more work is needed.

Wastes from stack gas cleanup constitute the largest effluent of solids and liquids from the power plant. For a limestone system, the solids consist mostly of calcium sulfite, with some sulfate, plus unreacted limestone and other reaction products. As mentioned earlier, HCl can be formed during combustion, forming $CaCl_2$ in the scrubber. Also, nearly all limestones contain some magnesium as well, which can form soluble $MgSO_4$. Calcium sulfate is sufficiently soluble to result in very hard water. Disposal of the large volume of scrubber waste could pose a formidable problem. It may be handled as a slurry containing 50 wt. percent water, and be sent to retention ponds. The high value land used for such disposal will not be available in many plant locations. The land area required for twenty years accumulation based on 65 percent load factor is very significant.

One approach to disposal is chemical stabilization of the waste to make it suitable as landfill. Chemical stabilization is being tested at TVA in EPA sponsored programs (9) using processes offered by Dravo Corporation, Chemfix Inc., and IU Conversion Systems, Inc. Leaching of these wastes must be considered, including the transport of soluble salts (sodium salts, etc.) introduced by slurrying with blowdown water. Perhaps the waste could be developed into a useful soil conditioner, or used as raw material for bricks, road construction, sewer pipe, etc. Slagging the waste would probably stabilize it as a road base, if the cost could be justified. Leaching of sulfurous compounds needs to be considered, in addition to leaching of soluble compounds such as those mentioned above. The latter are of particular concern, since many volatile trace elements in the coal will appear in the scrubber waste, and many of these volatile elements are toxic.

The net discharge of waste water from the plant is included with the scrubber waste, which is slurried mainly with blowdown water from the cooling tower. The latter water stream contains about 3,000 ppm of soluble salts brought in with the makeup water and concentrated in the cooling water circuit by evaporation in the cooling tower. In addition, the dissolved solids may be increased more than twofold by the contributions of $CaCl_2$, $MgSO_4$, and $CaSO_4$ discussed earlier. Thus, the water portion of the slurry waste could lead to unacceptable hardness and solids content if it gets into groundwater supplies. It does not appear to be acceptable for irrigation, or for discharge into inland rivers, although ocean disposal might be acceptable, where applicable. At present, the only possible disposal method seems to be storage in a very large pond, with positive control of seepage and overflow. Evaporation to a paste would ease the storage problem.

As previously mentioned, blowdown from the cooling tower is used to control buildup of dissolved solids in the cooling water circuit. Similarly, blowdown from the boiler controls solids content in steam generation, and serves as partial makeup to the cooling tower. Other miscellaneous waste streams of sludges and liquids come from treating the fresh water to make it suitable as makeup to the cooling tower or boilers. Chemicals used in water treating could include alum for coagulation and separation of suspended matter, lime to precipitate hardness, plus spent sulfuric acid and caustic from regenerating ion exchange resins used to demineralize boiler feedwater. These can be combined, neutralized, and included with the waste stream from limestone scrubbing.

Trace Elements

A great many trace elements are contained in coal; and although the concentration may be low, the total potential emissions can be very large when considering the total coal consumed in the U.S. Many of the trace elements are toxic; moreover, the emissions are concentrated at large power plant locations. For orientation, typical content of trace elements is given in Table 6 for Illinois No. 6 coal, together with a

Table 6

Base Case Estimate of Potential Trace Elements Discharged to Atmosphere Without Scrubber

Element	ppm in Coal (Dry Basis)	Average % Emitted	Emitted[b] kg/d
Antimony	0.5[a]	25	0.81
Arsenic	8 - 45	25	13 - 73
Beryllium	0.6 - 7.6	25	1.0 - 12
Boron	13 - 198	25	21 - 320
Bromine	14.2[a]	100	92.0
Cadmium	0.14[a]	35	0.32
Chlorine	400 - 1000[a]	100	2600 - 6500
Fluorine	50 - 167	100	320 - 1100
Lead	8 - 14	35	18 - 32
Mercury	0.04 - 0.49	90	0.2 - 2.9
Molybdenum	0.6 - 8.5	25	1.0 - 14
Selenium	2.2[a]	70	10.0
Vanadium	8.7 - 67	30	17 - 130
Zinc	0 - 53	25	0 - 86
Total			3094 - 8373

a - Not given in ECAS basis and therefore, not estimated.
b - Based on a feed rate of 6892 tpd of Illinois No. 6 coal.

total estimated discharge to the atmosphere for a 800 MWe plant based on CGA estimates (7) that used national average efficiencies for contact devices. It must be emphasized that these estimates do not take into account the effect of the FGD scrubber on controlling trace element emissions. Only actual tests at a power plant using Illinois No. 6 and the flue gas treatment equipment specified in this design could provide the data to assess the potential trace element problem.

The very large combined amount of these trace elements may be cause for concern as to possible environmental and health hazards. Many experiments have shown that all of the elements listed are partially volatile at combustion conditions, and most of them are known to be toxic in sufficient concentration. Tests also show that many of these elements become concentrated on the fly ash carried out with combustion gases, and the relative concentration of trace elements in particulates increases with decreasing particle diameter (6). Particulates leaving the stack after electrostatic precipitation have the highest concentration of all. Some elements such as Br, Cl, F, and Hg, are reported to leave in vapor form with the flue gases, as can be seen from the estimated '% emitted' column in Table 6.

The concentration of trace elements in fine ash, such as that collected in an electrostatic precipitator, raises questions as to safe methods for handling or disposing of such wastes. For example, if the wastes are dumped or used as land fill, there are serious questions of leaching and possible contamination of vegetation or groundwater. Fines collected in a stack scrubber raise similar questions about disposal. If fines are not adequately removed from the stack gas, then these contaminated particles may be dispersed into the air we breathe. Moreover, these fine particles also absorb liquid from the stack gas, giving an acid condensate containing sulfurous and sulfuric acid. HCl is apparently formed in the combustion process and may also be present. Therefore, a highly acid condition exists on the surface of the particle, which may activate or solubilize the trace element contaminants.

In one program (10), the fate of 37 trace elements in coal was traced through a power plant combustion system. Results showed that many of the 37 elements were appreciably volatile, becoming concentrated on the fine particles collected by electrostatic precipitation. Uncollected particles were even higher in concentration of trace elements. It was concluded that most of the bromine, chlorine, and mercury remain in the gas phase, along with much of the selenium. Appreciable volatility during combustion was also found for arsenic, cadmium, copper, gallium, lead, molybdenum, and zinc. Most of these have already been designated as toxic.

The flue gases entering the scrubber can contain mercury, arsenic, selenium, and possibly also chlorine, fluorine and bromine. The degree of removal of these materials in the scrubber will be a function of the scrubbing medium. It is likely that the halogens will be present as acids and be removed by aqueous scrubbing, but this is not certain, and it is therefore important to determine the form in which trace elements appear in order to develop suitable methods for their removal and deactivation. Stack gas cleanup may use scrubbing with lime, limestone, sulfuric acid, or other liquids. The chemical reactions that occur with trace elements will be different and need to be considered and evaluated on an individual basis.

It is clear that sizable amounts of undesirable or toxic elements are present in coal, that many of these are partially volatile during combustion and become concentrated on the finer particles, and appear to present a potentially serious environmental hazard. Studies are needed to show how to deactivate and dispose of them in an environmentally acceptable manner. It is most important that these studies be made before the potential problems become difficult and urgent.

Noise

Noise affects power plant employees and those in the immediate vicinity but does not have much impact on the rest of the surroundings. Thus, noise pollution is an occupational rather than an environmental problem. The occupational hazard of noise, as well as its general annoying influence in residential as well as commercial areas, has been the subject of recent Federal legislation. The Department of Labor Occupational Noise Exposure Standards specifies the Permissible Noise Exposure which relates to hearing protection.

Recently, Heymann, et al. (11) presented data indicating that the average sound pressure level around steam turbine generators rated at 700 MW is 94 dBa. Thus, according to the Department of Labor Occupational Exposure Standard, personnel may not be exposed to such a noisy environment for more than four hours per day. The noise level of other components of conventional power plants was measured by Broderson, et al. (12). Broderson et al. also established that power plant workers exhibit significantly greater hearing loss than the normal, non-noise exposed population. The hearing loss fits the general pattern of compensable, noise-induced hearing loss which increases with time exposure. The study established that 37 percent of the employees received an unacceptable high noise dose, resulting in an average hearing loss greater than 20 dB at 4000 Hz in 39 percent of the employees in the 35-50 age group, and 86 percent of the employees in the over-51 age group.

In order to avoid this occupational problem in power plants, a number of component manufacturers offer noise control options with potentially noisy equipment. The options include acoustically designed pipe laggings and enclosures for coupling, special enclosures for rotating equipment and valves, and acoustical treatment for the generator housing (13).

Regulatory Impacts

Currently, there is a substantial body of regulatory control over the electric utility industry. There are Federal and state emission standards covering existing plants for air, water, and solid waste. In addition, trace elements are receiving increasing attention. In the future, as more and more coal is utilized, pollution levels (e.g., CO_2 production, acid rain, inhalable particulates) would substantially increase without additional mitigating measures.

1.5 Performance

Current

The limitations on the obtainable efficiency from a coal fired steam-electric plant is well understood. Obtainable efficiency is substantially less than the ideal thermodynamic value. Even though boiler efficiencies are generally high in that most of the available energy in the fuel is transformed to the boiler working medium, it does not necessarily follow that the energy is substantially usable by the turbine. Turbine output is based not only on the energy available in the steam, but also on the energy in the steam flow and the steam temperature. As previously indicated, using 1000°F steam temperature and a body of water at 70°F for condensate cooling, we have a Carnot efficiency value of 64 percent. The only way to increase the Carnot efficiency value is to either increase the steam temperature (to the turbine) and/or reduce the heat sink temperature (for condensate). Furthermore, the actual turbine cycle is not as good as the Carnot cycle and, in addition, there are a number of system losses (e.g., friction, nozzle, etc.).

Unfortunately, the steam temperature to the turbine is limited by the metallurgical state-of-the-art coupled with very severe economic restrictions. In essence, materials that can tolerate higher than currently employed temperatures are rare, extremely expensive, and very difficult to fabricate.

On the turbine output side, the available energy from the boiler is not available when the working fluid reaches the sink temperature. In actual practice, the theoretical efficiency of each stage of a turbine can be calculated from the energy dissipated by the throughput working medium. The actual turbine efficiency is reduced by a number of unavoidable losses as previously indicated.

In the past (not currently), the National Coal Association, in their annual publication entitled "Steam Electric Plant Factors," provided steam-electric utility heat rates by region. The heat rate is the average number of Btu's required to produce a kwh of electrical energy. Table 7 provides regional heat rate values for coal fired plants for CY 1972 (14).

The values in the Table are believed to be fairly representative of the current overall situation. There are a number of recently completed plants around the world that achieve significantly higher efficiencies.

Table 7

Regional Heat Rate Values for Utility Steam Electric Plants

Area	Heat Rate	Average Regional Efficiency
United States	10,176	33.5%
New England	10,770	31.7%
Middle Atlantic	10,264	33.2%
E. North Central	10,300	33.1%
W. North Central	11,012	31.0%
South Atlantic	9,781	34.9%
E. South Central	9,882	34.5%
W. South Central	10,639	32.1%
Mountain	10,458	32.6%

The following, obtained from reference 15, is an indication of the current state-of-the-art in coal fired electrical generating systems. These U. S. coal fired boiler-turbine units are among the best in the world. The stated efficiencies are defined as:

$$\text{Efficiency} = \frac{100 \times \text{NEO}}{\text{TEC}}$$

where:

NEO = Net electrical output, expressed as units exported from the station during the year (having deducted all house load and auxiliary unit usage)

TEC = Total energy consumed in that year, expressed in kwh and based on the gross or higher calorific value of all fuel.

Utility Name	Power Station Name	Year	Size (MWe)	Load Factor	Efficiency
TVA	Bull Run	1975	950	74.9%	38.28%
Duke Power	Belews Creek	1975	1100	57.5%	38.21%
Duke Power	Marshall	1975	650	58.8%	38.07%

The values indicated, as based on available information, are assumed to not include efficiency reductions for flue gas desulfurization systems. A full scale flue gas desulfurization system is estimated to use an amount of energy equal to four percent of the output energy. This value includes one percent used for flue gas reheat. A flue gas desulfurization system that would only treat fifty percent of the flue gas is not expected to require reheat and correspondingly, would use an energy level of one to one and one-half percent of the plant output. The above systems would have overall efficiencies of approximately 36.7 percent with full scale flue gas desulfurization and 37.7 percent if only half the gas is cleaned.

Projected

The peak efficiency value of on-line coal-fired conventional steam electric plants is not expected to show any significant improvements through the 1990's over what is currently being attained. The generation of electric energy by conventional boiler steam turbine plants is certainly a very mature technology. The losses and limitations are very well understood. At best, a coal-fired steam-electric plant is not expected to achieve a 40 percent overall operational efficiency value. The expectation, based in part from inputs by industry sources, is that without FGD, the value could be between 39 to 40 percent. With FGD, a peak efficiency value of 38 percent appears reasonable. This equates to a projected 4 percent improvement over current capabilities.

1.6 Economics

Current

The economics of the current situation is indicated by the cost of a new coal fired steam-electric plant and the present selling price of utility generated electric energy. It should be noted that considerable spread exists on electric rates and on construction costs. In addition, when making comparisons, it is necessary to define what is included in cost values.

The time it takes to bring a new plant on-line has increased over the past ten to fifteen years. This is due in part to additional legal requirements (i.e., site justification, impact studies, inprocess inspections, various permits, etc.). Increased construction time combined with the high cost of money has a significant impact on a final cost. Total construction cost includes, but is not limited to: (1) land for plant and possible effluent disposal, (2) coal handling and associated facilities, (3) steam turbine plant, (4) electrical system, (5) A-E cost with contingency, (6) interest during construction, (7) escalation during construction, (8) permits, assessments, etc. In view of the above, reference 4 provides the following CY 1976 per kWe cost for a 800 MWe unit as follows:

Furnace/steam boiler	$ 110
Steam turbogenerator	66
Stack-gas cleanup	139
Balance of plant	320
	$ 635 per kW of installed capacity

The indicated values do not include land cost and provisions for on-site disposal. A general rule of thumb is that a complete plant will cost in the area of $800 to $1000 per kW installed capacity.

The mid-1979 selling price of electric energy to industrial customers varied from approximately 27 to 40 mills per kilowatt-hour. The breakdown of cost components is typically as follows:

1. capital component - 66.6 percent (of total),
2. operation and maintenance - 7.4 percent, and
3. fuel component - 26 percent (16).

Projected

As in any economic projection, there is an element of uncertainty. Even so, for a number of reasons, electric plant and electric energy cost have risen faster than the cost-of-living index. It is expected that future cost in terms of current dollars will similarly increase. This would be due in part to rising construction cost, high interest rates, rising fuel costs, and increasing environmental expenses necessitated by increasing use of coal. Both plant capital cost and electric rates are expected to increase at 3 to 7 percent per annum over the inflation level through 1985 (17).

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2. Diesel Generators

2.1 Overview

The diesel generator is an internal combustion engine that works on the cylinder and piston principle. Fuel is injected after the air is compressed and because of the thereby attainable high compression ratios, efficiencies greater than for the conventional gasoline internal combustion engine are achievable.

Diesels have been commercially utilized for in excess of 80 years. They are used extensively to power moderate size stationary electric generators for a variety of services. Even though the output of a large diesel generator is small compared to the output of a typical utility fossil fuel steam-electric generator, the attainable efficiency is generally as great or greater.

Recently, concern has developed relating to the potential carcinogenic aspects of diesel exhaust. Future utilization of stationary diesel generators may well depend on diesel emission control standards.

The cost of diesel derived electric energy is somewhat higher than that from a conventional steam-electric plant. This is due to the relatively high operating cost (per kwh electric energy) of a diesel-generator installation. DOD experience indicates diesel derived electric energy is at least twice as expensive as that supplied by an electric utility. Even so, for selected applications, diesel generators are very appropriate.

2.2 Process Description

Concept

The diesel generator is simply a diesel engine mechanically coupled to an electrical generator. Diesel engines have been commercially employed for over 80 years. With advancements in metallurgy, refinements in engine design, and improvements in lubricating capabilities, modern diesels generally operate at substantially higher rpm and (consequently) are much lighter than older engines of the same output capability. Currently, stationary diesel engines adaptable to electric generation are catalog listed with ratings up to 48,000 horsepower (1).

The diesel is an internal combustion engine and works on the cylinder and piston principle. Depending on application, these cylinders may be in-line, opposite, a V arrangement, or radial. Radial groups can be stacked to form the so-called pancake arrangement.

Diesels are compression ignition engines. In the "ideal" (i.e., commonly termed) diesel cycle, a charge of air is compressed without heat being added or rejected (i.e., adiabatically). Compression (400 to 700 pounds/square inch) is limited by the strength of the engine with compression ratios generally between 12 to 22. Fuel is injected at or near the end of the compression cycle. Due to the high temperature of compressed air, burning begins as soon as the fuel enters the combustion volume within the cylinder. Ideally, the rate of injection of the fuel should be adjusted to the travel of the piston so as to maintain constant pressure until the fuel injection is stopped. The next two operations are like those of a normal gasoline cycle (Otto cycle) engine, adiabatic expansion of the gas and cylinder heat rejection. In practice, it is not possible to obtain constant pressure burning (2,3).

The relative high efficiency (as compared to a gasoline cycle) is due to the attaining of substantially high compression ratios. Higher compression ratios are attainable since the fuel is injected at or near the end of the compression cycle. Analyses indicate that the efficiency of the diesel cycle increases with increased compression ratio and is greater at less than full load (2).

Detail

The Otto cycle or the four stroke constant combustion cycle is the one used in most internal combustion cycles. The Diesel cycle is similar to the Otto cycle except heat is supplied at constant pressure compared to constant volume for the Otto cycle. The modern diesel engine does not exactly follow the so-called diesel or constant combustion pressure cycle and has a higher thermodynamic efficiency value. The diesel fuel oils are crude oil distillates intermediate in volatility between kerosene and lubricating oils. As a rule, no ignition provisions are required for the higher compression ratio engines. Engine speed control in reaction to lead changes is controlled by varying the quantity of injected fuel (4).

Diesel engines are often used as prime movers for small power plants. Large, relatively slow rpm diesel engines have outstanding reliability, and the obtainable efficiency rivals that of the best fossil fuel fired steam-electric plants. However, the largest diesel plant size is smaller than a conventional fossil fuel fired steam-electric plant of the same output capacity.

Figure 3 is a diagram of a typical diesel driven generating plant. The heat balance of a diesel driven generator is relatively simple. The input energy is supplied by diesel fuel oil. The input energy less losses equal the output power. Table 8 indicates a reasonable heat balance for a diesel generator plant producing 5 MW of electrical energy. Figure 4 diagrammatically indicates the distribution of the total input energy.

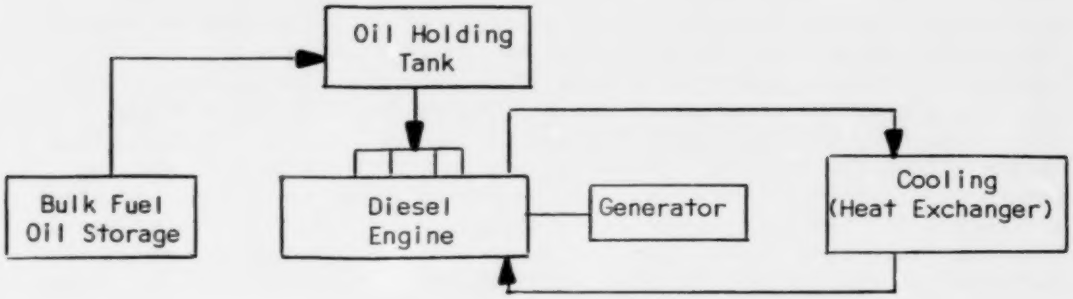
Oil Holding Tank
Bulk Fuel Oil Storage
Diesel Engine
Generator
Cooling (Heat Exchanger)

Figure 3

Diesel Driven Generator Plant

Table 8

Heat Balance for 5 MWe Diesel Electric Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Electrical Energy Output	17.06	33.0
Losses		
Incomplete fuel combustion	0.10	0.2
Diesel engine losses (friction, etc.)	3.00	5.8
Heat rejected (cooling and exhaust gas)	30.81	59.6
Generator losses	0.73	1.4
Total Energy Input	51.70	100.0

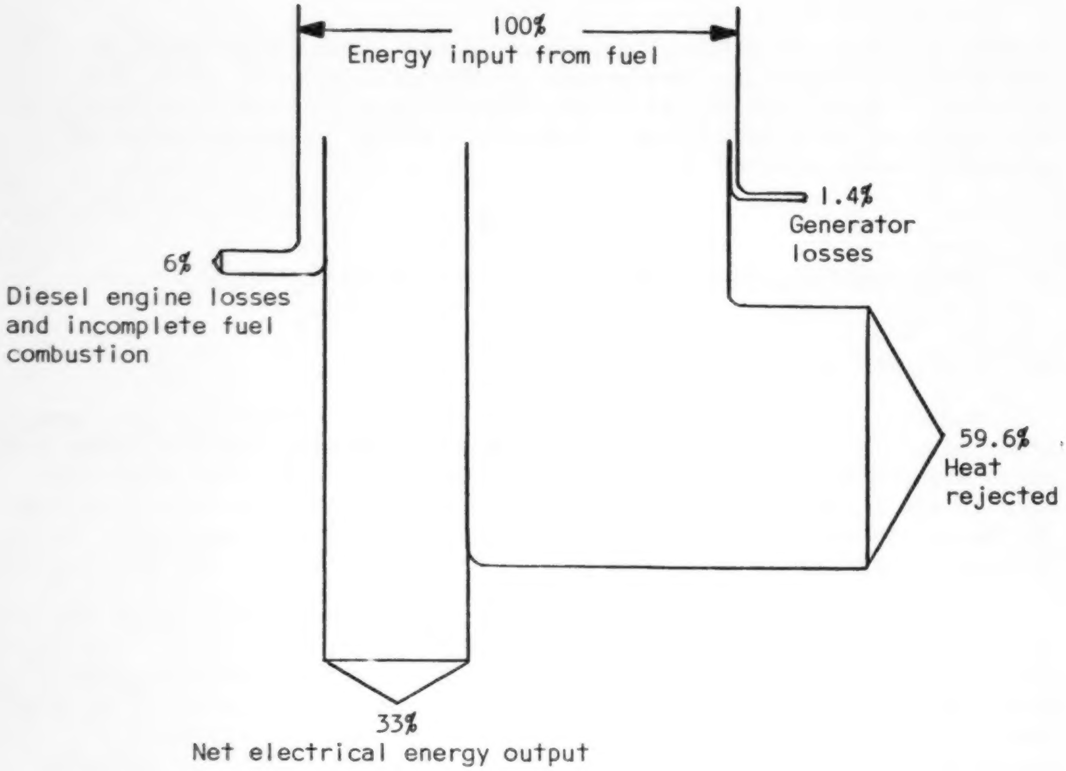
100%
Energy input from fuel
1.4%
Generator losses
6%
Diesel engine losses and incomplete fuel combustion
59.6%
Heat rejected
33%
Net electrical energy output

Figure 4

Heat Flow Diagram for Diesel Generator

2.3 Applications

Current

Diesel driven generators with their attractive thermal efficiencies and proven high reliability have made the diesel very popular for small power plants. Such plants are being used as the main or backup source of power for many consuming sectors. These include electric utilities, major military installations, hospitals, shopping centers, office buildings, schools, industrial activities, and others.

There are many reputable domestic and foreign manufacturers of stationary diesel engines. A partial listing of manufacturers include Worthington, Fairbanks Morse, Electric Motor Division of General Motors, General Electric, Alco Power, Sulzer Bros. Ltd., and Copper Bessemer. Some foreign designs are manufactured by domestic manufacturers. The majority of units used by utilities, the military services and others are less than 5,000 horsepower. Even so, a number of larger units are currently being utilized (1).

Projected

The projected applications are the same as current applications.

2.4 Environmental Considerations

Diesels emit significant amounts of soot-like exhaust and associated other constituents. Until relatively recently, the environmental concerns associated with diesel emissions have not received much attention. This is due in part, especially in a period of fuel availability concerns, to the reputation diesels have for high efficiencies as compared to the internal combustion gasoline engine.

The principal emissions from a diesel engine are particulates, CO, and NO_x. The level of emissions (for diesels as a class) varies considerably with engine design and operating conditions. The particulates from the diesel exhaust are composed of large particles (up to 10^4 A) and small particles (100-800 A). The particles are composed primarily of carbon but up to thirty percent of the particle may consist of hydrocarbons with at least three but usually up to six condensed benzene rings. Some of these aromatic hydrocarbons are known carcinogens (5).

Recently, there has developed considerable concern relating to the carcinogenic potential of the very fine soot-like particle emissions (polynuclear organic material) and the high NO_x emission associated with diesel exhaust. This concern has been substantially heightened by the high emission levels from diesel powered automobiles. This is an area just starting to receive significant attention. The U. S. Environmental Protection Agency is currently investigating the potential health effects and investigating pollution control technology. Currently, there does not appear to be a viable means to satisfactorily reduce or restrict emissions of concern. It is suspected that any effective emission control measures would have a significant adverse effect on the obtainable engine efficiency.

2.5 Performance

Current

The first diesel engine for commercial service was installed in St. Louis, Missouri in 1898. Within a few years, thousands of diesels were in use. Today, diesels range in size from 15 to 45,000 horsepower. A general rule of operation is that to prevent operational impairment, a stationary diesel should not be run at no load or with slight load (1). A state-of-the-art diesel driven generator carrying a 70 to 75 percent load should have an efficiency value of approximately 33 percent (1). Even so, it should be noted that many large diesel generators show overall efficiency values of 37 percent (6).

Projected

The projected use of diesel generators is the same as the current use. The technology is very mature and future efficiency values are not expected to be higher than those currently attainable. However, it should be noted that if stringent environmentally related restrictions are placed on diesel emissions, future utilization prospects could be severely impaired.

2.6 Economics

Current

The cost of diesel generated power to an industrial user, in part due to economy of scale factors, is generally significantly higher than electric utility provided power. The real cost of diesel generated power must include the capital (i.e., amortization) component as well as the operation and maintenance component.

Currently, DOD estimates the capital cost of a 1,000 kW skid mounted diesel generator assembly at approximately $500 per kW capacity. For a 1,500 kW unit, the estimated capital cost is approximately $400 per kw capacity (1).

A recent diesel generator operation and maintenance cost associated with the generation of 65,000 Mwh of electrical energy (over a one year period) was in excess of 60 mills per kwh (1). This value does not include the capital amortization component. In essence, the overall cost to provide a kwh of electrical energy via a diesel generator is considerably higher than utility provided power. Even so, for selected applications, the utilization of diesel generators are fully justifiable.

Future

The cost of electrical energy from diesel generators is expected to increase somewhat faster than the rate of inflation. This is mainly due to the expected continuation in the foreseeable future of the recent cost trend of diesel fuels (7).

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3. Fluidized-Bed Combustion (FBC)

3.1 Overview

A fluidized-bed boiler involves passing air upward through a thick (several feet) bed of granular, noncombustible material such as coal ash with limestone or dolomite. The air fluidizes the granular particles and, with the relatively small amount of air used to inject the fuel, serves as the combustion air. The basic advantages are 1) the ability to burn high-sulfur fuel with resulting low SO_x and NO_x emissions and 2) the potential for boilers of reduced size and weight (i.e., as compared to conventional boilers of equivalent capacities).

Two variations of fluidized-bed technology, atmospheric and pressurized, are being supported by the U. S. Department of Energy. Atmospheric fluidized-bed combustion can be used for the same purposes as a conventional boiler. Pressurized fluidized-bed combustion is oriented for use with combined cycle gas/steam turbine systems to generate electrical energy. The viability of a pressurized fluidized-bed combustor may well depend on the ability to adequately remove particulate material from the gas before it reaches the turbine.

Current fluidized-bed combustion efforts are largely in the R&D stages. Some manufacturers are just starting to advertise the availability of atmospheric commercial/industrial scale units. The attainable boiler efficiency is limited by the same general loss components as for a conventional boiler. Boiler efficiency values equal to those attainable by conventional boilers will depend on the ability to achieve substantially complete carbon burn-up.

The environmental aspects of a fluidized-bed boiler are similar to that of an equivalent capacity conventional boiler with flue gas desulfurization (FGD) burning the same coal. A major difference is the amount and nature of the spent bed material as compared to the effluent from a FGD system. For atmospheric fluidized-bed combustion with the same SO_x removal, almost three times as much limestone is required. Spent bed material from a fluidized-bed boiler contains appreciable CaO (i.e., quicklime) that may present handling and disposal problems. Hopefully, commercial uses will be found for the spent bed material.

In the near term, fluidized-bed boilers are projected to compete with industrial/commercial scale conventional boilers. Currently operating fluidized-bed boilers are mainly in the development, test and evaluation categories. It is expected that fluidized-bed boilers will be economically competitive with conventional units with SO_x emission control.

3.2 Process Description

Theory

A fluidized-bed boiler involves passing air upward through a thick (several feet) bed of granular, noncombustible material such as coal ash with limestone or dolomite. The air fluidizes the granular particles and, with the relatively small amount of air used to inject the fuel (usually coal but possibly other fuels), serves as the combustion air. Some of the heat transfer can be through tubes embedded in the fluidized-bed because combustion takes place at temperatures (approximately 1,600°F) that hopefully will not damage the tubes (1).

The fluidized-bed boiler, which can combust coal in a bed of inert ash with limestone or dolomite, hopefully, has two basic advantages. These are:

1) The ability to burn high-sulfur coal (all ranks) with resulting low sulfur dioxide and nitrogen oxides emissions. The sulfur dioxide formed during combustion of the coal will react with the limestone or dolomite sorbent to capture a major portion of the sulfur values from the combustion gas. Due to the low operating temperature, the formation of nitrogen oxides is minimized as compared to a conventional boiler.

2) If it is found that dependable cost effective operation is possible with a portion of the boiler tubes embedded in the fluidized-bed, then the attainable high release rate and heat transfer coefficient would permit reduced boiler size and weight. However, a substantial operating history will be required to fully substantiate that embedded boiler tube operation is indeed cost effective.

Two variations of fluidized-bed combustion technology, atmospheric and pressurized, are being pursued by the U. S. Department of Energy. Atmospheric fluidized-bed combustion can be used for generating electricity. However, current indications are that it will principally be employed for process or space heating due to efficiency considerations. Pressurized fluidized-bed combustion is oriented for use with a combined cycle gas/steam turbine system to generate electricity. In the pressurized variation of fluidized-bed technology, combustion takes place at an approximate 100°F higher temperature. Pressure within the combustor is maintained at a design value of 4 to 16 atmospheres (2).

In the pressurized-bed combustor, particulate removal must be accomplished before the gases enter the gas turbine in order to prevent blade damage. The viability of pressurized fluidized-bed technology may well rest on the yet unproven ability to adequately and efficiently clean the turbine gas feed.

Detail

Fluidized-bed combustion is a technology which involves the combustion of coal in a bed of inert ash with limestone or dolomite that has been fluidized (held in suspension) by the uniform injection of air through the bottom of the bed at controlled rates. The sulfur dioxide formed during the combustion of the coal reacts with the limestone or dolomite sorbent to form a dry calcium sulfate solid. No additional sulfur control devices are anticipated to enable FBC to meet current New Source Performance Standards (NSPS) and emission standards for SO_2 for selected applications. Users may elect to remove pyritic sulfur in coal preparation plants prior to combustion if economics favors such operation. NO_x emissions will also meet current standards. The formation of NO_x is minimized because of the low operating temperature in the fluidized-bed (approximately 1600°F) as compared to conventional combustion, in which temperatures may reach 3000°F (2).

The advantages envisioned by DOE for FBC include increased energy conversion efficiencies through the ability to operate using coal as the fuel without the operational requirement to power a scrubber system, relatively early commercial availability, a projected cost competitive with other near-term technologies, reduced emissions of SO_2 and NO_x, and the ability to burn all types and ranks of coal as well as char and refuse.

Figure 5 is a conceptual presentation of a fluidized-bed steam generator and does not indicate various arrangements (e.g., fuel feed). Figure 6 is a schematic diagram for an atmospheric fluidized-bed system with a steam turbine load. Figure 7 is a schematic diagram for a pressurized-bed system with both steam turbine and gas turbine loads (3).

Atmospheric fluidized-bed combustion is controlled in the temperature range of 1500-1650°F with excess air values of 20-25 percent. Steam produced in tube bundles and/or water walls located within the combustor may be converted to electricity in a conventional steam turbine cycle or may be used for process and/or space heating. SO_2 and NO_x control is accomplished in the combustion zone by reaction of SO_2 with limestone and reduced temperatures, respectively (2).

The portion of the coal ash which is small enough to be elutriated from the bed must be removed, along with attrited limestone, prior to releasing the flue gas to the atmosphere. Particulate removal can be achieved with cyclones, precipitators, and advanced fabric filters. The balance of the ash, along with the large particles or reacted limestone, is drained out of the bed (2).

The elutriated ash may be high in unburned carbon and its direct disposal would result in a lowered combustion efficiency. It is anticipated that atmospheric units will employ either a carbon burnup cell (CBC), a high-temperature, high-excess-air bed to which the collected ash is fed and burned, or will allow for the reinjection of collected ash into the combustor (2).

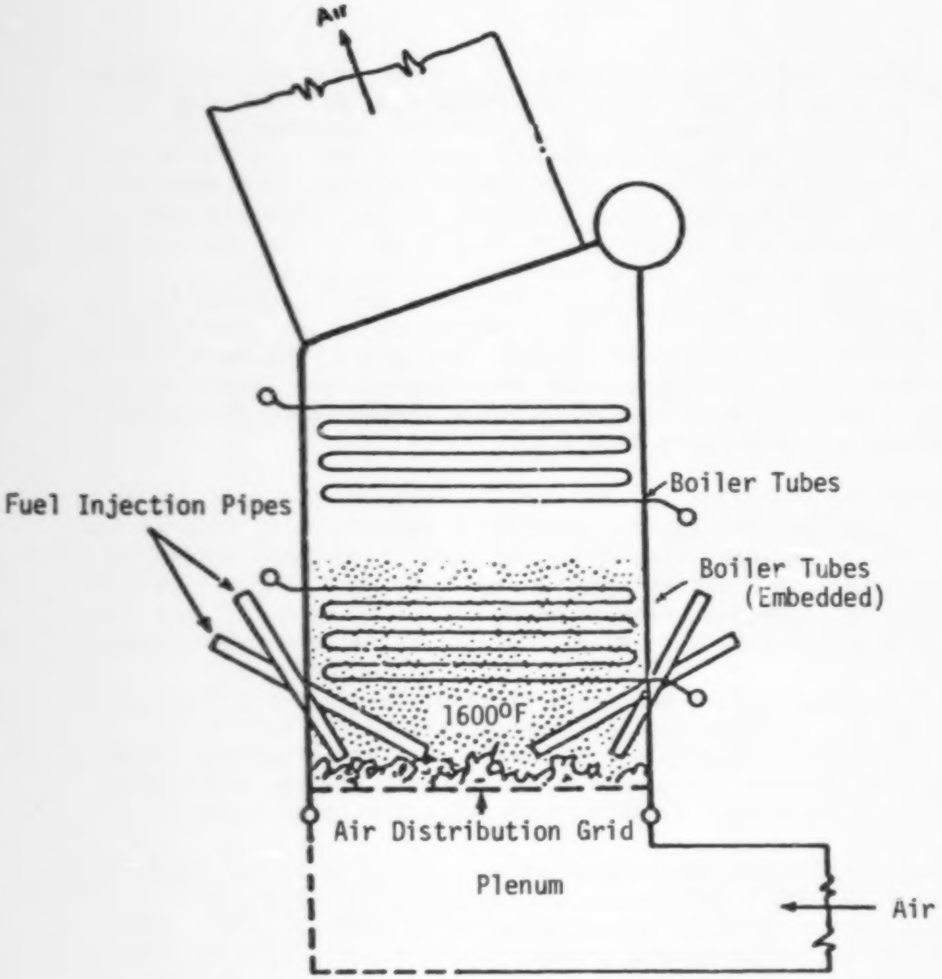
Air
Boiler Tubes
Fuel Injection Pipes
Boiler Tubes
(Embedded)
1600°F
Air Distribution Grid
Plenum
Air

Figure 5

Fluidized-Bed Steam Generator

The first U. S. pilot plant (30 MWe) for atmospheric fluidized-bed combustion began test operations in late 1976 at Rivesville, West Virginia. Demonstration-scale industrial applications are in the design, construction, and evaluation stages. Preliminary design is also underway for an AFBC demonstration plant in the 200 MWe range, with operation expected in approximately 1982. The use of AFBC for industrial heat and steam is anticipated in the early 1980's (2).

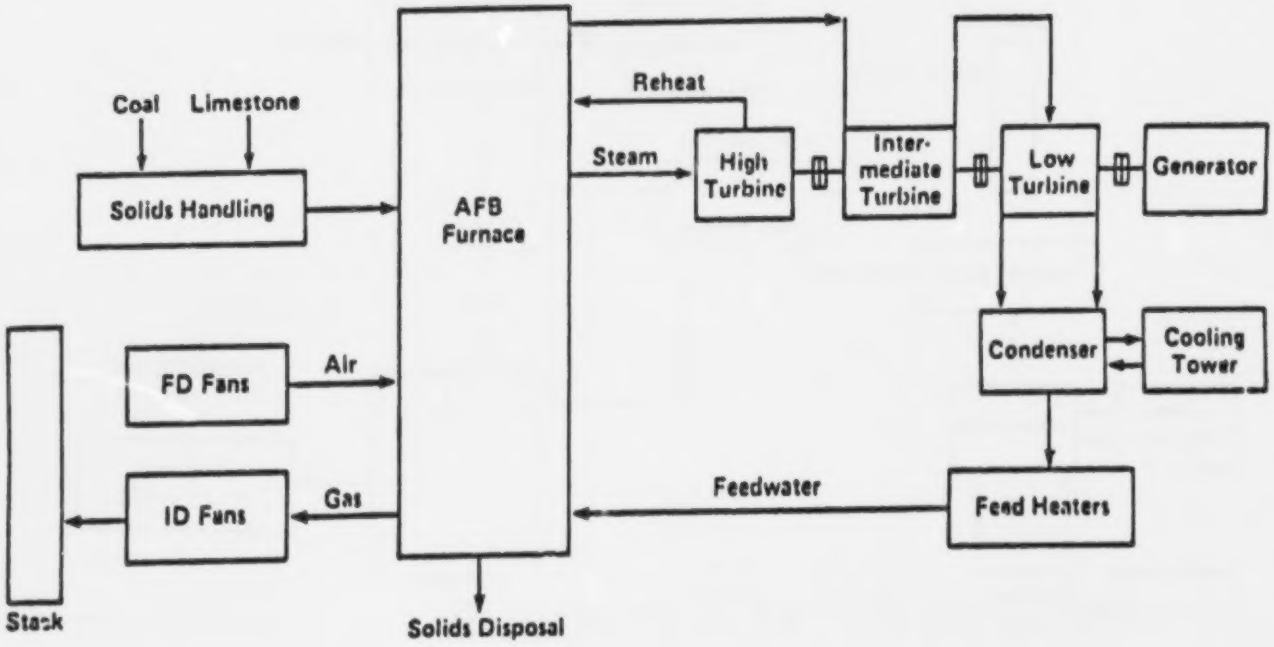
Coal
Limestone
Solids Handling
AFB Furnace
Reheat
Steam
High Turbine
Inter-mediate Turbine
Low Turbine
Generator
Condenser
Cooling Tower
Feed Heaters
Feedwater
FD Fans
Air
ID Fans
Gas
Stack
Solids Disposal

Figure 6

Schematic Diagram for Atmospheric Fluidized-Bed System

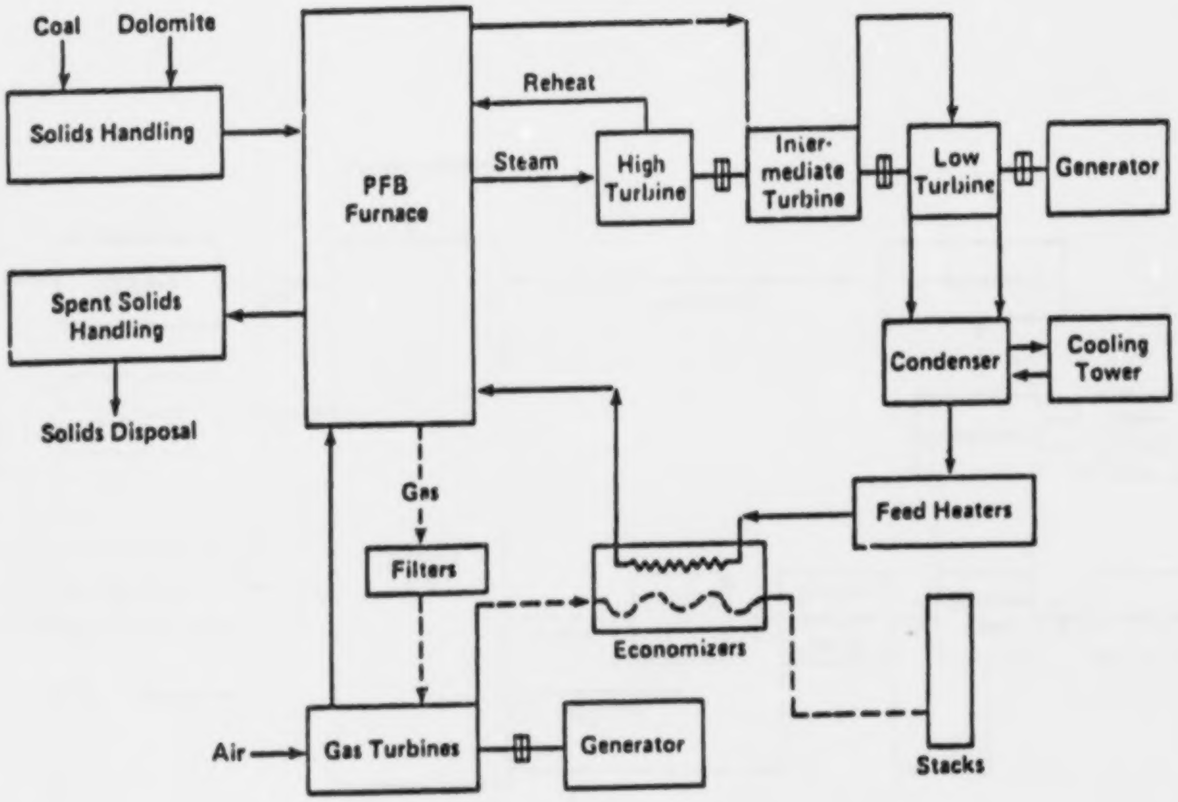
Coal
Dolomite
Solids Handling
PFB Furnace
Spent Solids Handling
Solids Disposal
Reheat
Steam
High Turbine
Inter-mediate Turbine
Low Turbine
Generator
Condenser
Cooling Tower
Feed Heaters
Gas
Filters
Economizers
Stacks
Air
Gas Turbines
Generator

Figure 7

Schamatic Diagram for Pressurized Fluidized-Bed System

In the pressurized variation of FBC technology, combustion occurs in a fluidized bed of sorbent which may be dolomite, with excess air ranges similar to those found in the atmospheric boiler and at temperatures approximately 55°C (100°F) higher. Pressure within the combustor is maintained at a design value of 4 to 16 atmospheres, possibly resulting in a significant size reduction compared to an atmospheric fluidized-bed combustor (2).

Exxon, under EPA sponsorship, has developed and operated a 0.63 MW equivalent pressurized FBC miniplant with sorbent regeneration. The purpose of the miniplant is to permit assessments of and develop controls for particulate, SO_2, and NO_x emissions from a pressurized FBC. This same pressurized miniplant has been used by DOE to assess tube performance in a pressurized FBC environment.

Pressurized fluidized-bed combustion systems are being developed for combined-cycle operation where energy conversion is achieved through gas turbines as well as through a conventional steam turbine cycle. One system being studied by General Electric for DOE is a pressurized fluidized-bed boiler with a power recovery gas turbine. A 13 MWe combined cycle pilot plant is being designed by Curtiss-Wright for operation at Woodridge, New Jersey. This plant will use a pressurized fluidized-bed combustor/air preheater coupled to a gas turbine and then to a heat recovery boiler. In pressurized FBC, particulate removal must be accomplished before the gases enter the gas turbine to prevent turbine blade damage. Devices (not yet proven) such as granular bed filters, ceramic filters, or felt metal filters will be needed to clean the gas sufficiently, and it is desirable to do this at the combustor exit. To improve combustion efficiency, the larger ash particles will be recycled to the combustor. The power output of a typical combined-cycle unit will be divided between the steam and gas turbines. Pressurized FBC systems for commercial utility use are not expected until approximately 1995 (2).

For both atmospheric and pressurized FBC systems, problems associated with disposal of spent sorbent, as well as raw sorbent requirements, can be largely reduced by employing a regeneration process, where sulfated sorbent is withdrawn from the combustion bed, regenerated, and returned to the bed for reuse. For commercialized systems, it is anticipated that the SO_2 (or H_2S) - rich gas produced in the regeneration process will be fed to a conventional sulfur recovery operation (located on site) and converted to either sulfur or sulfuric acid. Spent sorbents are being evaluated by DOE and EPA for utilization in agriculture and industry and for stable landfill disposal (2).

The energy loss components are essentially the same as for the conventional boiler and result in part from the following:

1. Heating excess combustion air
2. Incomplete fuel combustion

3. Heating of moisture in coal and air
4. Losses associated with energy in flue gas.

It should be noted that pulverized coal firing provides extremely efficient combustion of coal with the unburned combustible loss generally being less that 0.5 percent for bituminous coals. With stoker firing, the unburned combustible loss can be held to approximately 5 percent (i.e., with reinjection of initially unspent carbon).

Currently, the unburned combustible loss can be 10 to 15 percent for single pass combustion in a FBC unit. The most significant factor contributing to this loss is that the combustion temperature must be limited to 1500 to 1650°F range to achieve efficient SO_2 capture. Even though it may be possible to improve over the single pass FBC efficiency by collecting and firing the unspent carbon in a separate combustor, it is most unlikely that the attainable boiler efficiency of the FBC will ever reach that obtainable by a pulverized coal fired unit (4). It is expected that the unburned combustible loss for FBC with the collecting and firing of initially unspent carbon can be made to approach the stoker fired boiler value.

The required calcium to sulfur molar feed ratio may be 2½ to 3½ with the atmospheric FBC process to achieve 85 percent SO_2 removal with a 3 percent sulfur coal (i.e., meeting the NSPS). By contrast, the Ca/S feed for limestone scrubbing with the same coal is approximately 1.1. With a more restrictive SO_2 emission standard, the Ca/S ratio to provide a 90 percent removal could be 4 to 5 for FBC as compared to 1.3 to 1.4 for limestone scrubbing.

However, a pulverized coal fired boiler with FGD requires energy to operate the FGD system and often requires additional energy for flue gas reheat after cleaning. The additional energy required could equate to 3 to 4 percent of the rated energy output of a coal fired steam-electric plant.

Reference 4 indicates that there are considerable operational uncertainties including such items as 1) effects of in-bed tube corrosion under different gas flow velocities, 2) load responsiveness, 3) operationally achievable boiler efficiencies, and 4) realistic "overall" capital and operating cost. In essence, even though there is very considerable research and development in the FBC area, uncertainties exists. Undoubtedly, final utilization will depend on fuel availabilities, applicable environmental standards, capital and operating economics, and other items. It may well turn out that atmospheric FBC will prove attractive for commercial/industrial steam raising applications, but not for utility electric generating purposes where the overall efficiency depends not only on boiler efficiency but also on the steam quality fed to the turbines.

As previously indicated, in the near term, fluidized-bed boilers are projected to compete with conventional industrial/commercial scale boilers. Table 9 provides a reasonable anticipated heat balance based on relating the projected losses of an atmospheric fluidized-bed combustor with those of currently available spreader stoker fired boilers. Since the atmospheric fluidized-bed boiler is initially expected to compete with conventional industrial/commercial boilers, the provided table only covers boiler operation. The information in Table 9 can diagrammatically be illustrated by the Figure 8 heat flow diagram. It should be emphasized that the provided heat balance is at best a projection. The heat balance does not take into account the differential between heat of calcination (endothermic) and sulfonation (exothermic) reactions associated with the fluidized-bed. It is possible that for all practical purposes these values will offset each other.

Table 9

Estimated Heat Balance for 100 MBtu Output
Atmospheric Fluidized-Bed Boiler

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Heat Energy Imparted to Boiler Fluid	100.0	85.0
Furnace Losses		
Heating excess combustion air	0.24	0.2
Incomplete fuel combustion	5.88	5.0
Heating moisture in coal and air	4.71	4.0
Energy in flue gas	4.71	4.0
Miscellaneous (heat loss, etc.)	2.12	1.8
Total Energy Input	117.66	100.0

As previously indicated, pressurized fluidized-bed combustion is oriented for use with combined cycle gas/steam turbine systems to generate electrical energy. Table 10, based in part on reference 5, provides a considered projected heat balance for a pressurized fluidized-bed combined cycle plant. Diagrammatically this can be illustrated by the energy balance diagram, Figure 9. It must be emphasized that pressurized fluidized-bed systems are only in the early research and development stages and at best commercial utilization is many years off.

Table 10

Estimated Heat Balance for 903.77 MWe Advanced
Steam Cycle - Pressurized Fluidized-Bed Electric Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Electric Power Output		
Gas turbine derived power	699.49	
Steam turbine derived power	2520.31	
Less power (i.e., losses for fans, coal handling, pumps, transformers, etc.)	(136.01)	
		39.14*
Boiler Losses		
Heating moisture in coal and air	315.126	4.00
Incomplete fuel combustion	157.563	2.00
Heating excess combustion air	15.756	0.20
Miscellaneous (heat losses, etc.)	63.025	0.80
System Losses		
Stack Loss	441.176	5.60
Mechanical, frictional, etc.	157.563	2.00
Heat rejected to cooling towers and otherwise lost (e.g., through boiler blowdown)	3644.432	46.26
Total Fuel Energy Input (Coal)	7878.15	100.00

(Totals may not add due to independent rounding)

* Net value

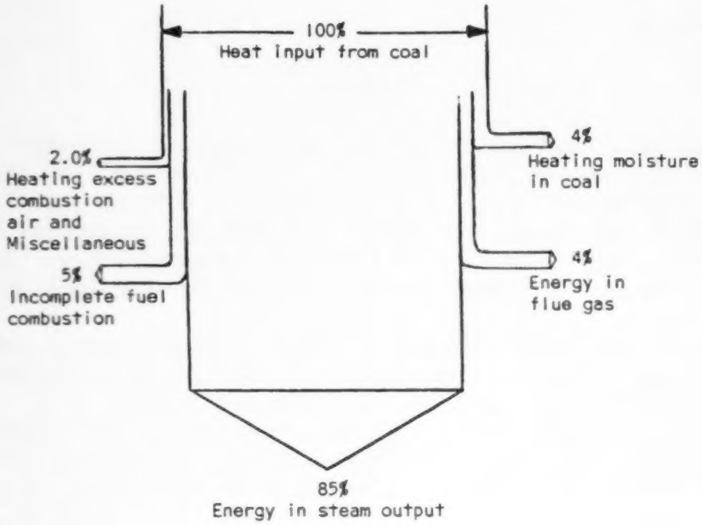
100%
Heat input from coal
2.0%
Heating excess combustion air and Miscellaneous
5%
Incomplete fuel combustion
4%
Heating moisture in coal
4%
Energy in flue gas
85%
Energy in steam output

Figure 8

Heat Flow Diagram for Atmospheric Fluidized-Bed Combustor

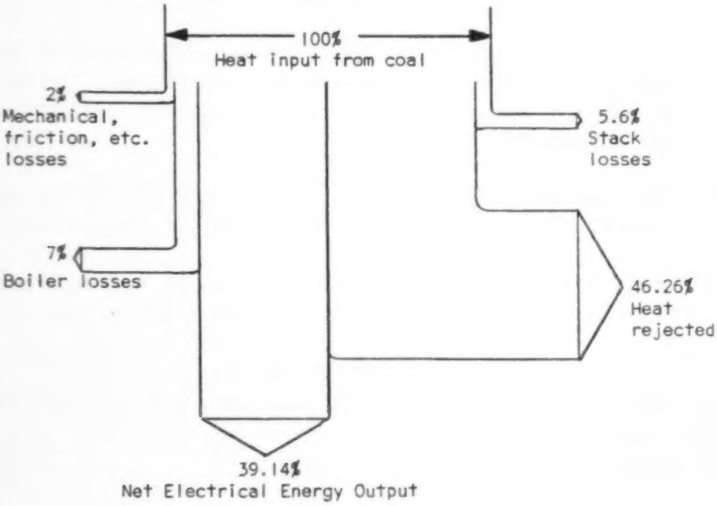
100%
Heat input from coal
2%
Mechanical, friction, etc. losses
7%
Boiler losses
5.6%
Stack losses
46.26%
Heat rejected
39.14%
Net Electrical Energy Output

Figure 9

Estimated Heat Flow Diagram for Advanced Cycle - Pressurized Fluidized-Bed Electric Plant

3.3 Applications

Current

Fluidized beds have been used for many years in the chemical industry for ore treating purposes. In contrast, the use of FBC for steam raising purposes is relatively new. Currently, FBC activities, oriented at steam raising purposes, are being pursued in a number of industrial countries around the world. In Europe, fluidized-bed combustors have been developed in which the boiler tubes are more conventionally located (6, 7).

Past and current FBC efforts for steam raising purposes have been pursued in England, France, Czechoslovakia, Germany and undoubtedly other countries. As indicated, past developments are take-offs of chemically related roasting concepts including those to desulfurize copper ores and to produce sponge iron. Past FBC steam raising concepts do not have the potential advantages of currently pursued U. S. efforts.

For all practical purposes, FBC activities in the U. S. are still in the research, development, and evaluation phases. Several reputable firms have recently begun to market commercial/industrial size units.

Projected

The projected applicability of FBC systems would be primarily for industrial/commercial boiler utilization. A Federally funded study (8) on the potential application of industrial steam raising FBC systems indicates that the potential is substantial and would make inroads when:

1) A reliable FBC technology is demonstrated and resulting units are capable of achieving continuous boiler operation (of about one year duration) with effective control of emissions, and

2) The economics of FBC technology are demonstrated to be competitive with alternative ways of firing solid coal.

Reference 8 indicates that the nationwide potential for FBC technology, assuming timely development and acceptable economics, is:

Year	Cumulative Number of Industrial FBC Boilers	10^{15} Btu per year
1980	7	0.01
1985	200	0.29
1990	685	0.99
1995	1170	1.69
2000	2050	2.97

(1×10^{15} Btu, i.e. one Quad, equates to approximately 165 million barrels of oil)

Most of the estimated potential is expected to be in the chemicals, petro-chemicals, petroleum refining, paper, primary metals, and food industries. Even so, it must be remembered that wide-scale industrial acceptance is uncertain.

The potential for generating utility produced electrical energy, as previously implied, is totally speculative and, at best, is much more remote. Currently, as based on competing options, the outlook would depend to a large extent on the successful development of a pressurized FBC capability so as to achieve significant improvements in the overall electric generating efficiency.

3.4 Environmental Considerations

Emissions from a fluidized-bed boiler can be classified as continuous, scheduled intermittent, and unscheduled intermittent. Continuous emissions include pollutants that are contained in the flue gas discharged from the furnace stack. Scheduled intermittent emissions include discharge of limestone (or dolomite) and ash to storage piles, and sulfur bearing wastes ejected from the bed. Unscheduled intermittent emissions include transients due to operating upsets, fugitive dust from coal, and storm run-off. For each boiler plant, all of these pollution sources must be considered thoroughly and controlled adequately. Pollution control methods may vary and will depend to a considerable extent on the specific plant. The environmental aspects of a fluidized-bed boiler bears a very close resemblance to that of a conventional boiler plant. The pollutants and their source are almost identical. A principal difference is the pollution associated with the spent bed effluent from a conventional plant. Conceivably, there may be a difference in the combination products due to low temperature burning. This could change the organic and trace element emissions.

Identified Pollutants

Areas of environmental concern are summarized in Table 11, based in part on an EPA funded study (9). In the following detailed discussion, emissions to the air will be discussed first, followed by a similar discussion of solids and liquid effluents, and then trace elements which are treated separately. The following is based, in part, on an assessment of the environmental aspects of a pulverized coal-fired boiler plant (9).

Air Emissions

The first area to consider is the coal preparation area, primarily coal storage and sizing. Wind action on the coal pile can cause a dust nuisance, especially during loading and unloading operations. Conveyors

Table 11

Emissions and Effluents from Fluidized-Bed Boiler

Emissions to Atmosphere	Potential Concerns
Wind action on coal storage and handling	Dust, fire, odors
Wind action on limestone and waste	Dust
Cleaned flue gas	NO_x, plume dispersion, dust, SO_x, POM
Possible fugitive dust from area	Dust nuisance
Transients due to upsets, cleaning, etc.	Dust, smoke, fumes
Potential noise and odors	Machinery, maintenance
Effluents - Liquids and Solids	
Rain runoff - coal, limestone, and waste areas	Suspended and dissolved matter
Spent bed effluent	Ground water contamination and land use
Sludge and chemicals from water treating	Minor
Trace Elements	
Leaching associated with disposal of spent bed waste	Soluble toxic elements
Fate of volatile toxic elements in coal feed	Contamination of local air and water
Emissions as gas and PM and POM with stack gas	Health hazard

should be covered to contain the dust, and water sprays may be needed at transfer points. As in all solids handling operations, leaks and spills are to be expected, and provisions should be provided for cleaning them up and hosing down the area so as to wash dust to a collecting pond before it becomes airborne (9).

The precautions used to prepare the limestone for the bed should be similar to those of coal, since the bed reagent (e.g., limestone) is often stored, sized, and used in a manner comparable to coal.

Sized coal and limestone is fed to the furnace where the coal is burned in an inert bed of ash and limestone. Spent bed material is generally dropped from the bed by gravity and removed by a water cooled screw, the spent material remaining in a dry state. Care must be taken to prevent dust emissions (10).

Flue gases from the furnace are a major environmental concern since they contain many pollutants including SO_x, NO_x, polynuclear organic matter (POM), trace elements, etc. At the present, there is no fully accepted way to remove NO_x from flue gas. However, in a fluidized-bed boiler, the formation of NO_x is reduced due to the low fuel burning temperature. SO_2 is removed by the limestone reacting with sulfur dioxide formed during combustion of the coal. Means such as baghouses, electrostatic precipitators, or scrubbers are used to reduce particulate emissions. It should be noted that submicron particles which are suspected of causing respiratory problems are not efficiently removed by an electrostatic precipitator.

As more information is obtained, other pollutants in the flue gas may become of concern. For example, nitrates, HCN, sulfates, and organic matter are areas now being examined. Also, it is known that chlorides in the coal are volatilized during combustion, and can leave in the flue gases as HCl. In many operating power plants, the HCl formed is presumably released to the air, but with limestone in the fluidized-bed, it conceivably could be removed by reacting with the limestone to form soluble $CaCl_2$.

Periodic cleaning of furnace equipment is required and precautions are needed to avoid emissions to the air at such times. One method of on-stream cleaning of heat transfer surfaces is called "soot blowing," using high velocity jets of steam to dislodge deposits. Most of the additional dust load will hopefully be recovered in the particulate collection system (e.g., bag-house). The deposits are made up of fine particles, which could be high in volatile trace elements according to indications from related studies. Equipment cleaning at shutdown or during the turnaround can also cause dust nuisances, or possibly a hazard in the case of deposits of toxic materials (9).

Solid and Liquid Effluents (4, 9)

The first effluent of solids and liquids covered are those from the coal and limestone storage piles and handling area. Here, rain runoff will contain suspended solids and may also contain soluble sulfur and iron compounds. The coal pile is subject to oxidation and weathering, with conditions similar to those associated with acid mine water. As one precaution, curbing should enclose the storage pile and any coal preparation area, so that runoff can be segregated and sent to a storm pond for settling. The water can then be treated prior to disposal or treated and used for plant purposes.

The next consideration is disposal of the spent bed material from the furnace. The spent material is usually removed in a continuous form and kept in a dry state. Because of the low calcium utilization, the spent solids contain substantial CaO in addition to $CaSO_4$, along with trace elements and other substances (e.g., MgO, SiO_2, Al_2O_3, iron oxide, ash, etc.). The presence of CaO (i.e., quick lime) may make the material unsuitable for direct landfill except in lined cavities and thereby substantially complicate disposal. CaO poses the potential for personnel hazard and any leachate may have a high pH. Hopefully, the waste will have economic value for such uses as building material, fertilizer, and neutralization of acid mine drainage. Some preliminary studies have been made by EPA and DOE with regard to bed waste, but much more work is needed.

The waste streams would be from rain runoff of coal and possibly exposed limestone and waste areas along with sludge and chemicals from boiler blowdown and boiler water treatment. Chemicals used for boiler water treatment could include alum for coagulation and separation of suspended matter, lime to precipitate hardness, along with many other currently used water treating agents. Rain runoff from coal has received considerable attention and control procedures are in current use. Adequate disposal of streams associated with boiler water conditioning and boiler waste has been ongoing. In essence, waste streams control should not pose any new or unique problems.

Trace Elements (9)

A great many trace elements are contained in coal; and although the concentration may be low, the total potential emissions can be very large when considering the total coal consumed in the U. S. Many of the trace elements are toxic; moreover, the emissions are concentrated at large boiler plant locations. The trace elements content of a No. 6 Illinois coal is given in Table 12, together with the average percent emitted as based on CGA (11) estimates that used national average efficiencies for contact devices. It must be emphasized that these estimates do not take into account the effect of particulate and SO_2 emissions control on controlling trace element emissions and are therefore upper bounds.

Table 12

Base Case Estimate of Potential Trace Elements
Discharged to Atmosphere Without Scrubber*

Element	ppm in Coal (Dry Basis)	Average % Emitted
Antimony	0.5**	25
Arsenic	8 - 45	25
Beryllium	0.6 - 7.6	25
Boron	13 - 198	25
Bromine	14.2**	100
Cadmium	0.14**	35
Chlorine	400 - 1000**	100
Fluorine	50 - 167	100
Lead	8 - 14	35
Mercury	0.04 - 0.49	90
Molybdenum	0.6 - 8.5	25
Selenium	2.2**	70
Vanadium	8.7 - 67	30
Zinc	0 - 53	25

* - Based on a No. 6 Illinois coal.
** - Not given in ECAS basis and therefore estimated (per Reference 9).

The very large combined amount of these trace elements may be cause for concern as to possible environmental and health hazards. Many experiments have shown that all of the elements listed above are partially volatile at combustion conditions, and most of them are known to be toxic in sufficient concentration. Tests also show that many of these elements become concentrated on the fly ash carried out with combustion gases, and the relative concentration of trace elements in particulates increases with decreasing particle diameter (12). Particulates leaving the stack after electrostatic precipitation have the highest concentration of all. Some elements such as Br, Cl, F, and Hg, are reported to leave in vapor form with the flue gases (see Table 8) (9, 11).

The concentration of trace elements in fine ash, such as that collected in an electrostatic precipitator, raises questions as to safe methods for handling or disposing of such wastes. For example, if the wastes are dumped or used as land fill, there are serious questions of leaching and possible contamination of vegetation or groundwater. Fines collected in a stack scrubber raise similar questions about disposal. If fines are not adequately removed from the stack gas, then these contaminated particles may be dispersed into the air we breathe. Moreover, these fine particles also absorb liquid from the stack gas, giving an acid condensate containing sulfurous and sulfuric acid. HCl is apparently formed in the combustion process and may also be present. Therefore, a highly acid condition exists on the surface of the particle, which may activate or solubilize the trace element contaminants (9).

In one program (13), the fate of 37 trace elements in coal was traced through a power plant combustion system. Results showed that many of the 37 elements were appreciably volatile, becoming concentrated on the fine particles collected by elctrostatic precipitation. Uncollected particles were even higher in concentration of trace elements. It was concluded that most of the bromine, chlorine, and mercury remain in the gas phase, along with much of the selenium. Appreciably volatility during combustion was also found for arsenic, cadmium, copper, gallium, lead, molybdenum, and zinc. Most of these have already been designated as toxic.

It is clear that sizable amounts of undesirable or toxic elements are present in coal, that many of these are partially volatile during combustion and become concentrated on the finer particles, and appear to present a potentially serious environmental hazard. Studies are needed to show how to recover them, or how to deactivate and dispose of them in an environmentally acceptable manner. It is most important that these studies be made before the potential problems become difficult and urgent (9).

Regulatory Impacts

Currently, there is a substantial body of regulatory control that would apply to fluidized-bed boiler plants. There are Federal and state emission standards covering coal fired plants for air, water, and solid waste. Recently, more stringent NSPS have been promulgated for SO_x, NO_x, and particulate emissions from utility sources. In addition, trace elements are receiving increasing attention. In the future, as more and more coal is utilized, pollution levels would substantially increase without additional mitigating measures.

3.5 Performance

Current

Current activities are mainly in research, development, and demonstration stages. Existing boilers are still in the development stages and therefore, current performance value would not necessarily be representative of future operations.

Projected

The expectation of proponents of FBC technology is that a fluidized-bed boiler will favorably compete with conventional boilers with FGD systems. Even so, it should be noted that more restrictive SO_2 emission limitations might not be readily achievable with a fluidized-bed fired boiler and the amount of limestone required for the same SO_2 removal would be substantially greater than for the FGD approach.

Boiler efficiencies of fluidized-bed boilers are not expected to surpass the values obtainable for conventional pulverized coal fired boilers with an FGD system. It is expected that the principal reasons would be due to incomplete carbon burnup and the amount of energy required to maintain the air flow through the fluidized-bed.

FBC Technology is expected to have the greatest near term impact in the commercial/industrial boiler size categories. Developed units would permit the more readily burning of coal at such locations as schools, hospitals, shopping centers, office buildings, small industrial parks, etc. The applicability of FBC technology to the utility sector is believed to depend on the successful development of a pressurized FBC capability. This appears to be considerably in the future.

3.6 Economics

Current

As previously indicated, all domestic FBC activities are basically developmental and testing. There are no commercially operating plants that could provide current (non-R&D) economic operating costs.

Projected

Current projections by the U. S. Department of Energy are that the capital cost of an atmospheric fluidized-bed boiler plant would be about the same as for a conventional boiler plant with a FGD scrubber. In addition, the total operating costs are expected to be comparable. The expectation is that even though the limestone requirement will be greater, this would be offset by a reduction in labor costs.

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4. Combined Cycle Power Plants

4.1 Overview

In the context of power generation, the term combined cycle was, until recently, applied only to the combination of two turbine cycles utilizing two different working fluids in electrical generation plants in which the waste heat from the first turbine cycle provided the heat energy for the second turbine cycle. However, with the development of more advanced generating technologies which do not necessarily rely on turbines, the term now encompasses any combination of cycles using separate working fluids operating at different temperatures. Combined cycles of gas turbine-steam, diesel-steam, and mercury-steam have seen varying degrees of commercial service. Of these, the combined open-cycle gas turbine and steam turbine power plant appears to offer the best prospects for having its existing technical problems solved in the near future. Some configurations being developed could provide generating efficiencies of over 50 percent based on the heating value of the clean fuel as delivered (1). This value would be degraded by the energy losses incurred in providing the clean fuel (e.g., coal conversion). However, efficiencies of 40 percent or better are projected.

There are many gas turbine-steam combined-cycle power plants currently in operation which achieve overall efficiencies around 40 percent (2). However, these systems currently rely upon gas or oil whose price and future availability have obviously become of serious concern. Therefore, there is major emphasis on making today's turbines run more efficiently on these scarce fuels and to develop improved turbines that will operate efficiently on the synthetic fuels that will one day replace oil and natural gas (3).

In addition to improved efficiency, such combined-cycle power plants utilizing gas-turbine and steam-turbine technology have a number of other key features which could make them particularly appealing to the utility industry. Besides very fast start-up capabilities, these features include low capital investment per kilowatt of generation, low operating costs, and the capability for use as a base-load or peaking power plant. Another potentially promising aspect of the combined-cycle power plant is its projected ability to use low-energy gas from coal. The environmental implications of this are significant. Since such low-Btu gas could be clean burning, much of the environmental control problems and expense associated with conventional coal-fired steam generating plants could be avoided (4).

A variation of the combined gas turbine and steam turbine system features the direct combustion of coal in a pressurized fluidized-bed (PFB). Although internal particulate control is still required, the PFB offers the potential for direct combustion of high-sulfur coal without stack gas cleanup while achieving an overall coal pile-to-bus bar plant efficiency in excess of 40 percent (5).

Some of the more exotic generation technologies currently under development fall into the category of combined cycle because of the manner in which they might be efficiently applied as a power system. These combined cycles which have been proposed include steam-organic fluid, gas-organic fluid, liquid metal-steam, and MHD-steam (6). Since these systems are substantially different from the other combined cycles being considered and are at such varied levels of development, they will only be discussed to a limited degree in this section.

4.2 Process Description

Concept

A combined cycle has been described as a synergistic combination of cycles operating at different temperatures, each of which could operate independently (6). Synergistic is an appropriate modifier in that the heat rejected by the higher temperature cycle is recovered and used by a lower temperature cycle to produce additional power, thus as a system realizing improved overall efficiency. To qualify as a combination, the individual cycles must operate on separate fluids. Among these combinations which have been commercially applied are diesel-steam, mercury-steam, and gas turbine-steam. Still in the development stages are combined cycles of steam-organic fluid, gas-organic fluid, liquid metal-steam, and MHD-steam (6).

As stated above, each cycle in the combination is operating at a different temperature. The higher temperature cycle is referred to as the topping cycle and the lower temperature cycle as the bottoming cycle. By generic category, topping cycles which have been practically applied include Otto, Brayton, and Rankine cycles. All bottoming cycles have been of the Rankine type.

In practice, a topping cycle consisting of a gas turbine or diesel engine is used to drive electric generating equipment. Should MHD be the topping cycle, the electric current would be generated directly. The principal heat rejected by these possible topping cycles is in the form of sensible heating in the exhaust products of combustion. This is the heat that becomes available to the bottoming cycle as the exhaust gas is cooled through a range of temperatures. The heat is imparted to the working fluid of the bottoming cycle, typically steam, which drives additional power generating equipment. Depending upon the overall economics of the particular system, it may be advantageous to supplement the heat recovered from the topping cycle with additional heat to operate the bottoming cycle. However, whether the bottoming cycle is unfired or supplementary fired, it is this "captured" heat, which would otherwise be lost, that is the key to the improved efficiency of combined cycle systems.

For most bottoming cycles, it appears that steam will remain the predominant fluid for the foreseeable future. The advantages of steam Rankine bottoming cycles have so far prevailed and, with the exception of a few experimental installations, all commercial bottoming cycles have used this medium (6). Some of the advantages of steam are low cost, chemical stability and inertness, high specific heat, and high heat transfer rates. The disadvantages of steam include low molecular weight, high latent heat, and high critical pressure. However, some of these disadvantages can and are being mitigated at the expense of some cycle complexity.

Detail

As noted earlier, gas-steam turbine combined cycle generating systems are currently available to efficiently serve utilities in base, intermediate and peaking modes. Unfortunately, these contemporary systems rely on premium fuels. A schematic representation of such systems and the typical efficiency attainable under current technology is provided by Figure 10 (3). Gas and light distillate oils have been the most widely used fuels in the past. Heavy distillates, residual, and crude oils have also been used, but treatment is necessary to remove or inhibit the contaminants

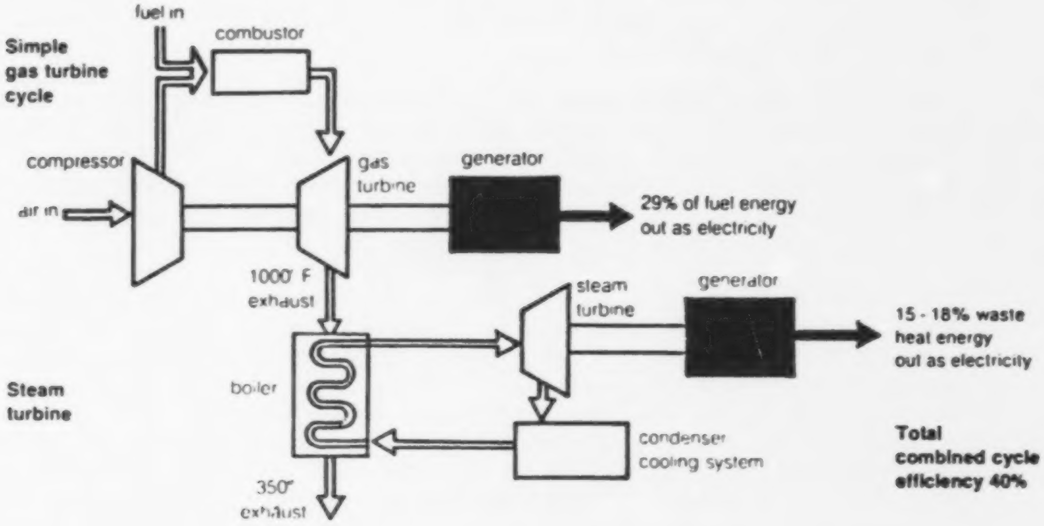
fuel in
combustor
Simple gas turbine cycle
compressor
air in
gas turbine
generator
29% of fuel energy out as electricity
1000° F exhaust
steam turbine
generator
15 - 18% waste heat energy out as electricity
boiler
Steam turbine
condenser cooling system
Total combined cycle efficiency 40%
350° exhaust

Figure 10

Simplified Schematic of Combined Gas and Steam Cycle Generating System normally present which cause corrosion. To cope with the ever increasing problem of supply and price of these premium fuels, greater use of coal and coal derived liquid and gaseous fuels is seen as a viable alternative. Therefore, the most promising combined cycle plant configurations being considered are directed at using such fuels along with improved gas turbine performance.

Although there are many such configurations in various stages of conceptual and practical design, there are four possible combined cycle power plant systems which have been and are being actively studied (1, 7). These systems, three of which were assessed by Energy Conversion Alternatives Study (ECAS) are: 1) a high-temperature combined cycle using coal-derived gaseous and liquid fuels; 2) a high-temperature combined cycle using a low-Btu coal gasifier integrated into the compressed-air path of the combined cycle; 3) a supercharged boiler combined cycle using a pressurized coal-fired fluidized-bed boiler in the compressed-air path of the combined cycle; and 4) a low-temperature (1600-1800°F) combined cycle using a pressurized coal-fired fluidized-bed combustor in the compressed-air path of the combined cycle. All of these combined cycle systems are only conceptual at this point.

High Temperature Combined Cycle Using Coal Derived Liquid Fuel

This particular combined cycle configuration, depicted in Figure 11, is arranged essentially like existing gas-steam turbine combinations. The differences are the higher operating temperatures and the use of a clean, coal-derived liquid fuel. Under the conditions assumed for this combined cycle arragement, the topping cycle is an advanced gas turbine with inlet temperatures around 2400°F coupled with a heat recovery steam generator. Based upon the Btu content of the clean, coal-derived fuel, an overall thermal efficiency of near 50 percent is projected. This will be degraded to about 40 percent if consideration is given to the energy lost in the conversion process. Such a fuel must not only be clean enough to meet environmental standards, but also must have low erosion and corrosion properties to protect the gas turbine blades. Variations in the steam bottoming cycle include options for supplementary fired steam boilers, alternative steam pressure levels, and the use of steam induction that affect both cycle efficiency and plant cost, and therefore, the ultimate cost of electricity.

The higher gas turbine inlet temperature of this configuration requires the use of either cooled or ceramic blades. Turbine inlet temperatures in excess of 1800°F require either cooling of the vanes and blades so as not to exceed critical metal temperatures or the use of high temperature ceramic construction. Air cooling of vanes and blades is presently used by the industry for turbines operating in the range of 1900°F with units under development capable of reaching 2100°F. Advanced gas

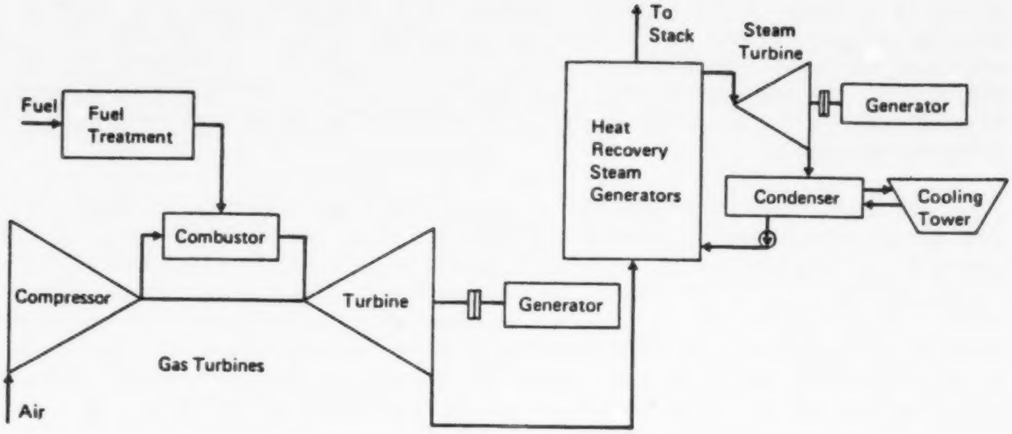

Figure 11

Simplified Schematic of High Temperature Combined Cycle Using Coal Derived Liquid Fuel

turbine cooling concepts include extension of air cooling to 2500°F, the use of water cooling to reach 3000°F, and the use of ceramic vanes and blades capable of withstanding temperatures from 2400 to 3000°F (1).

The simplicity, environmental acceptability, and high projected efficiency of this combined cycle configuration is particularly appealing. However, further advances in high temperature gas turbine technology, and the development of an economically sound process to produce a high-Btu liquid from coal will determine the future application of this combined cycle arrangement in the electric power generating industry.

High Temperature Combined Cycle With Integrated Low-Btu Gasifier

As shown in Figure 12, this configuration employs a gasifier with its own cleanup system to provide the gas turbine topping cycle with a low-Btu gas. The technical and economic feasibility of this arrangement is based upon this coal derived gas being sufficiently free of particulates, sulfur, and nitrogen to eliminate the need for any final emission control apparatus as well as not being damaging to the gas turbine components. As shown in Figure 12, the air-blown pressurized gasifier and associated cleanup equipment fit into the compressed air flow path of the gas turbine to provide for coal firing of the turbine. Development efforts currently are centered on both fixed-bed and fluidized-bed gasifiers, but future development may include entrained-bed gasifiers (1).

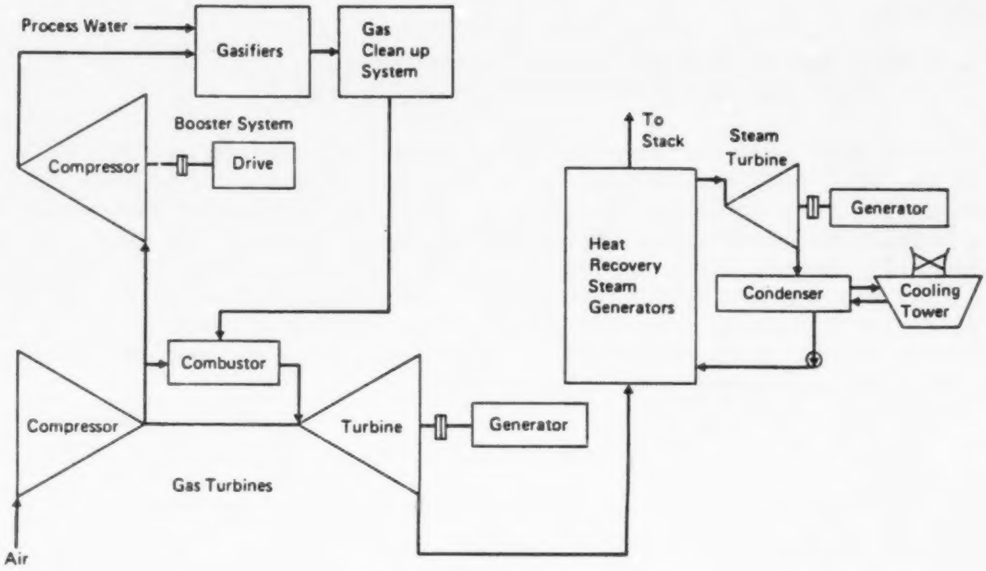
Process Water
Gasifiers
Gas Clean up System
Booster System
Compressor
Drive
To Stack
Steam Turbine
Generator
Heat Recovery Steam Generators
Condenser
Cooling Tower
Combustor
Compressor
Turbine
Generator
Gas Turbines
Air

Figure 12

Simplified Schematic of High Temperature Combined Cycle
With Integrated Low-Btu Gasifier

The inclusion of a gasifier in the compressed-air flow path has the effect of reducing the overall efficiency as compared to the previously discussed combined cycle system using coal derived oil. Based upon various configurations of this combined-cycle arrangement addressed by the ECAS, efficiencies approaching 47 percent were the upper limit (based on the Btu content of the clean, coal derived gas). Since the bottoming cycle is the same, this drop in efficiency is definitely attributed to the gasifier addition. Two particular gasification concepts were investigated by ECAS: 1) an air-cooled gas turbine with a fixed-bed gasifier and a cold gas cleanup train; and 2) an air-cooled gas turbine with a fluidized-bed gasifier and a hot gas cleanup train. The desulfurization of the low-Btu gas occurs in the cleanup train with the fixed-bed units and in the gasifier with the fluidized-bed units. The cold gas cleanup train removes particulates, heavy oils, and sulfur compounds. The hot gas cleanup train removes particulates. It is the cooling of the fuel gas that introduces an efficiency loss.

As noted previously, this combined cycle plant configuration is only conceptual at this point. The success of such an advanced power generating concept will rely on continued achievements in air cooling of turbines, economic low-Btu gasification of coal, and economic gas cleanup systems.

Supercharged Boiler Combined Cycle Using Pressurized Coal-Fired Fluidized-Bed Boiler

As seen by the schematic representation presented as Figure 13, this is the most complex combined cycle configuration addressed thus far. The thrust of this design is to use a gas turbine to augment the output from a pressurized coal-fired fluidized-bed boiler plant. The gas turbine, operating on gas furnished by the fluidized-bed, is used to pressurize the boiler and the gas turbine exhaust is used to heat the boiler feedwater above 190°F. Power from the gas turbine is added to that produced by the steam cycle side of the plant to provide about 20 percent of the net power from this conceptual generating system.

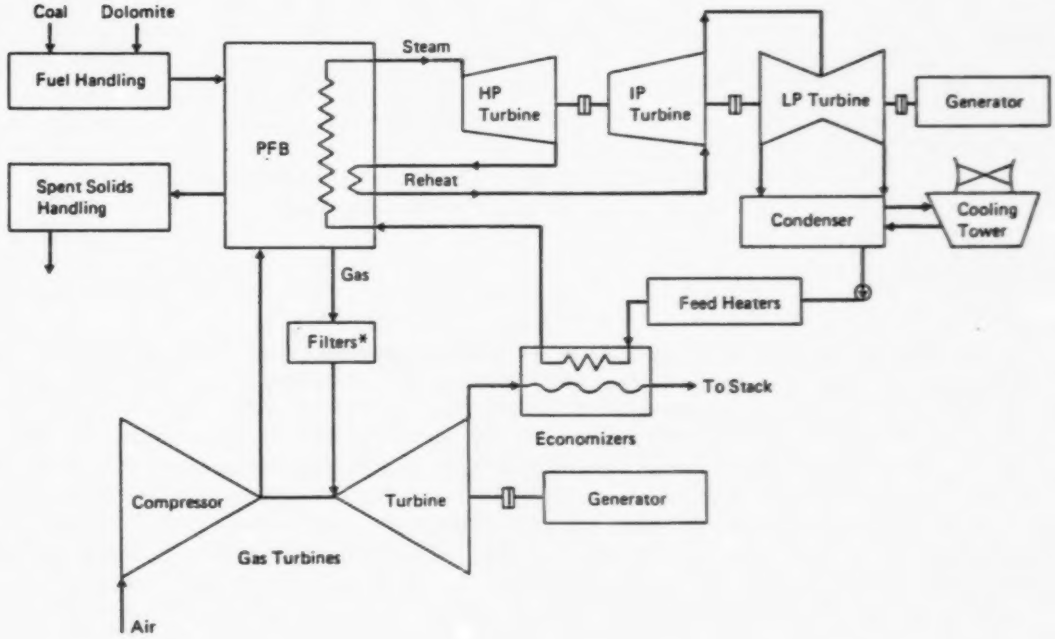
Coal
Dolomite
Fuel Handling
Steam
PFB
HP Turbine
IP Turbine
LP Turbine
Generator
Reheat
Spent Solids Handling
Cooling Tower
Condenser
Gas
Feed Heaters
Filters*
To Stack
Economizers
Compressor
Turbine
Generator
Gas Turbines
Air

Figure 13

Simplified Schematic of Supercharged Boiler Combined Cycle Using Pressurized Coal-Fired Fluidized-Bed Boiler

The performance of this configuration is limited by the permissible outlet temperature from the fluidized-bed combustor/boiler. Since the gas leaving the fluidized-bed to feed the gas turbine is not over 2000°F, the temperature at the gas turbine inlet is equally low. In spite of this, the overall efficiency is projected to be close to 40 percent since the arrangement permits the direct burning of coal without any associated conversion or external environmental control losses.

Several power plant design options are available: steam turbine inlet conditions, ratio or gas turbine power to total plant power, and gas turbine inlet conditions. The best steam conditions appear to be near or above critical steam pressure but with 1000°F throttle and reheat temperatures. The capital cost rises sharply as more austentic steels are required in the steam system, offsetting the small reduction in electricity cost that accompanies an improved heat rate. The cost of electricity from a power plant with a supercharged boiler is also relatively insensitive to gas turbine inlet temperatures and to the gas turbine-to-steam turbine power ratio at values below 0.2 (1).

Again, we are looking at a conceptual design whose practical implementation is contingent upon an economic and technically sound pressurized fluidized-bed boiler, development of efficient and reliable hot gas cleanup equipment, and development of a 1600 to 1800°F gas turbine with the construction to withstand the increase loading of gas-borne contaminants directly into the turbine.

Low-Temperature Combined Cycle With Pressurized Coal-Fired Fluidized-Bed Combustor

Another possible variation of the combined cycle utilizing fluidized-bed is to replace the standard combustor used in a gas turbine (see Figure 11), with a coal-fired pressurized fluidized-bed combustor without in-bed heat removal. Designs of this type are characterized by higher heat rates than are presently being projected for other combined cycle configuration because of the lower gas turbine inlet temperatures (1600-1800°F). Whether or not units of this type will ever serve in base load utility plant application is doubtful. However, smaller scale industrial sized plants may find acceptance since they would permit the direct burning of coal in an environmentally acceptable fashion.

As in the previous combined cycle design, the ultimate success hinges on development of efficient and reliable fluidized-bed combustors, hot gas cleaning equipment, and gas turbines capable of satisfactorily operating at higher dust and corrosive loadings in the working gas.

There have been many indepth studies addressing the performance of combined cycle power plants. Of particular current interest are combined cycle concepts that are fueled by coal through the use of an integrated gasifier. Such a configuration, the High Temperature Combined Cycle with Integrated Low-Btu Gasifier, has previously been described. Reference 8 addresses the energy balance of such a concept employing the Combustion Engineering Low-Btu coal gasification process. The reference 8 analysis is predicated on advanced gas turbine designs with a 2400°F combustion outlet temperature. Such turbines are not presently available, but with development, reference 8 indicates an expected availability in the 1981 to 1985 time period.

Table 13 provides a heat balance based on reference 8. Diagrammatically, this can be illustrated by the heat flow diagram of Figure 14. This diagram indicates energy distribution on a percent of total input basis.

Table 13

Estimated Heat Balance for 1200 MWe Coal Fueled Combined Cycle Power Plant with Integrated Low-Btu Gasifier

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Electrical Power Output		
Gas turbine derived power	3,024	28.26
Steam turbine derived power	1,050	9.81
System Losses		
Ash/slag (combustibles and sensible heat)	138	1.29
Gasifier loss (heat loss)	153	1.43
Sulfur product	103	0.96
Power losses (electrical, mechanical etc.)	154	1.44
Condenser (steam turbine and compressor turbine)	3,505	32.76
Fuel gas compressor coolers	819	7.66
Cooling for gas cleanup unit	179	1.67
Stack losses	1,541	14.40
Waste water steam heat losses	34	0.32
Total Energy Input	10,700	100.0
(Input energy: 95% coal, 5% from auxiliary power, blower and turbine air.)		

Based on gasifying 10,000 ST/day of Illinois No. 6 coal with a coal feed rate of approximately 420 tons per hour and a plant rating of approximately 1,200 MWe.

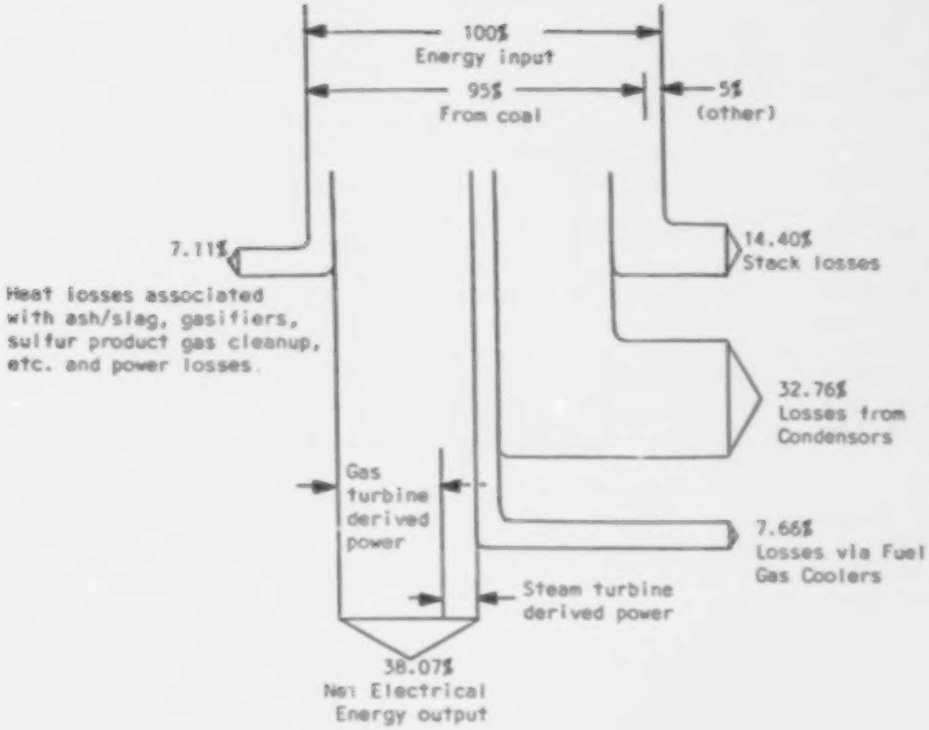
100%
Energy input
95%
From coal
5%
(other)
7.11%
Heat losses associated with ash/slag, gasifiers, sulfur product gas cleanup, etc. and power losses.
14.40%
Stack losses
32.76%
Losses from Condensors
Gas turbine derived power
7.66%
Losses via Fuel Gas Coolers
Steam turbine derived power
38.07%
Net Electrical Energy output

Figure 14

Heat Flow Diagram Based on Table 13

4.3 Applications

Current

There are numerous gas turbine-steam combined cycle plants presently operating in intermediate and base load capacities at utility plants in various parts of the country. For example, the Westinghouse Electric Corporation has installed many units during this decade for Public Service of Oklahoma, El Paso Electric, Florida Power and Light, Southern California Edison, and others. These have been units rated at up to 260 MW, installed either singularly or in series which are capable of burning various grades of oil and/or gas (9). The other major domestic manufacturer of such plants is General Electric with United Technologies, Curtis Wright, Brown Boveri, and others offering various combined cycle configurations.

Certainly, plants consuming these increasingly scarce and costly fuels (oil and gas) do not provide a long term solution to meeting this country's electric power generating requirements. Therefore, any large scale implementation of such combined cycle plants will only be strategically and economically acceptable with the advent of clean burning synthetic fuels most probably derived from coal. Even so, on a near-term basis, there is a role for combined cycle plants.

An example of such a near-term role is where, because of environmental constraints, power plants cannot be converted to burn cheaper, more abundant coal. In this situation, combined cycle power plants could provide more economical and efficient base load power generation than conventional oil and gas burning systems. The more obvious and most immediate application of the existing gas turbine-steam combined cycle design is in areas such as the Southwest where fuels such as natural gas are, for the moment, plentiful locally (3).

Another contemporary application of combined-cycle is the repowering of existing conventional plants by the addition of a combustion turbine. Based upon the desired impact, a wide variety of repowering configurations are available. Some of the basic reasons for repowering may include (10):

- Efficiency improvement resulting from repowering,
- Increase in capacity at existing sites,
- Increase in capacity without increase in cooling water requirement,
- Shortage of new sites for new power plants,
- Air pollution difficulties with the existing plants,
- Minimum environmental impact of the repowered plant,
- Avoidance of cost, difficulty and delay involved in approval of new sites,
- Boiler plant in need of extensive overhaul or replacement.

One of the simplest forms of repowering consists of using the exhaust heat from the combustion turbine to heat the feedwater for a conventional gas or oil fired steam plant in place of the steam extracted from the steam turbine. Under this arrangement, additional power is produced by the combustion turbine and by the steam no longer used by the feedwater heaters now expanding to the condenser. Repowering can also be applied to pulverized-coal burning plants. Unfortunately, such an application presents a variety of technical and economic problems which may negate the potential benefits. For example, when combustion turbine exhaust gas is used as the source of boiler oxygen, the flow (and velocity) of exhaust gas through the boiler is increased. However, the intake of oxygen to pulverized coal fired boilers is deliberately limited to minimize fly ash erosion. Therefore, the increase in gas velocity resulting from the increased exhaust gas flow may be unacceptable. Under such conditions, steam flow of a repowered coal-fired boiler may have to be restricted. Additionally, the economizer would have to include soot blowing and water wash capabilities to control fouling. Further, a special low-oxygen burner is also needed, as well as a primary air mover because the conventional air preheater will be removed. A final feature limiting the application of repowering to coal-fired plants is that the equipment costs are higher than for their oil and gas fired counterparts (11).

Repowering has only been applied to a limited degree in the past because the availability of relatively inexpensive fuels has until now minimized the importance of achieving higher thermal efficiencies. However, as the price of gas and oil continues to go up along with their questionable long term availability, the improvement in heat rate offered by repowering makes it more attractive than ever for utility applications (11). Besides being economical, a repowered plant would be more efficient, using as much as 20 percent less fuel than the conventional oil-fired plant. It is estimated that twenty thousand or more megawatts of this nation's old, inefficient oil-burning capacity cannot be converted to coal for economic or environmental reasons. If those plants were repowered with combined cycle systems, the greater efficiency made possible by the gas turbine's waste heat recovery system could save over 150,000 barrels of oil per day (2).

Projected

There has been a slump in the United States market for gas turbines since 1973 when it became clear that the future price and availability of clean fuels was less than desirable (12). However, the General Electric Company, one of the principal turbine manufacturers, now forecasts a two-thirds increase in the worldwide gas turbine market during the next ten years over the previous decade. This projected increase will be mainly due to the development of larger, more efficient units and their use in gas-steam turbine combined cycle power plants (13). In addition to achieving efficiencies in excess of conventional fossil plants, there are other attributes of such combined cycle systems which can make them more attractive for power generation in the near future. These include lower installation cost, shorter installation schedules, more flexible operational capabilities, and half the water requirements of a conventional steam plant. Another factor that makes combined-cycle plants attractive to utilities is the ready availability of factory-constructed portable control rooms providing computer control systems that load units automatically to achieve a desired megawatt demand (4). These highly sophisticated control systems can start each piece of equipment, accelerate and synchronize the turbine generators, and direct a complete plant shutdown in the event of a normal stop mode. The systems not only get the unit on and off line faster, but also provides less chance for equipment damage by reducing the number of personnel required to operate a plant and the level of training and experience necessary to achieve reliable performance.

In this country, one of the primary factors giving impetus to the use of such gas-steam turbine combined cycle plants fueled by natural gas and light distillate oil is their environmental acceptability. Increasingly stringent emission regulations, permit requirements, and citizen opposition to other, less costly, alternative energy sources such as coal encourage a continued expansion of this generating approach. However, as stated before, the use of these high grade clean fuels is strategically and economically unacceptable in the long run. Therefore, any new generating capacity of this type should have the capability to not only burn residual and other low grade fuels, but also synthetic fuels which will eventually be derived from coal and oil shale. Thus this technology could continue to be an alternative for efficient electric power generation through the time of dwindling oil and natural gas supplies to a time of more abundant synthetic fuels. When such fuels are available, then it will be practical to implement them on other than a peaking and intermediate load basis.

On a large scale, combined cycle plants will be very desirable when fluidized-bed combustor/boiler technology is perfected for utility size application. This will permit the direct combustion of high sulfur coal without the energy losses attributed to conversion and external environmental controls. Another promising, but more indefinite, role for combined cycle power systems will come toward the end of the 1990's when fuel cells and MHD are projected to be commercially available. These technologies are discussed separately in their respective sections of this publication.

4.4 Environmental Considerations

As discussed previously, there is not one single unique combined cycle power plant, but instead, a potentially infinite number of cycle combinations to comprise such a system. Therefore, when addressing the environmental aspects of combined cycle power plants, it is more appropriate to identify the effluents associated with the individual cycles. These cycles may be applied in a topping or bottoming role, depending upon the particular generation system configuration.

Identified Pollutants

Of the combined cycle systems which have seen commercial service, only the gas-steam turbine type can be considered to be currently applicable to electric power generation. There are no significant liquid or solid pollutants from this system and the air emissions are currently quite low since present configurations use gas turbines burning high grade fuels (light distillate oil and gas). Subsequent generations of the gas-steam turbine combined cycle systems will be designed to consume lower grade, hotter burning fuels which will result in an associated increase in air emissions. Those combined cycle systems incorporating a fluidized-bed combustor/boiler have their own set of air, liquid, and solid effluents. This also applies to the combined cycle configurations with an integrated low-Btu gasifier. The effluents associated with more advanced cycles such as fuel cells and MHD have been projected and are covered in their respective sections of this document.

Air Emissions

Contemporary gas-steam turbine combined cycle systems burning light distillate or natural gas have no significant sulfur or particulate emissions. The only emission of any consequence is NO_x. Although it results in an increase in the carbon monoxide emitted, NO_x is controlled by the injection of demineralized water or steam into the combustor. Since the injection technique requires water of high purity to avoid deposits on turbine blades and other components, water treatment (and associated sludge disposal) may be required. Alternative control techniques for reducing both thermal and, to a lesser extent, fuel NO_x include: alterations to the combustion temperature and residence time; use of a two-stage combustion system; or use of a catalytic combustor. Fuel refining to reduce nitrogen content of fuels, or stack gas scrubbing, are being considered for controlling fuel-related NO_x (14).

The gas-steam turbine combined cycles configurations utilizing a pressurized fluidized-bed (PFB) boiler/combustor offer several environmental advantages. The fluidized-bed, with limestone or dolomite addition, permits the direct combustion of high sulfur coal without need for flue gas desulfurization. As the sulfur in the coal burns to SO_2, it is removed from the combustion gases through the reaction of the SO_2 and $CaCO_3$ (limestone) and air to form solid $CaSO_4$ and CO_2 gas. Based upon various proposed configurations, SO_2 can be reduced to within the utility New Source Performance Standard (NSPS). The NO_x emissions from a PFB are also substantially below the levels encountered in conventional coal fired furnaces since conversion of air nitrogen is eliminated by low combustion temperatures and NO_x from fuel-bound nitrogen is lessened due to partial reduction by the dolomite sulfation reactions (5). Total NO_x emissions are projected to be between 0.2 and 0.3 lb per MBtu as compared to the utility NSPS of 0.5-0.6 lb per MBtu. Anticipated particulate emissions are also quite encouraging, projected to be well below the utility

NSPS of 0.03 lb per MBtu. Although it has not been proven in utility size units, the PFB boiler/combustor integrated with a gas-steam combined cycle plant is projected to not only meet the current emission limits, but also have the capability to meet the progressively more stringent standard anticipated in the future. Some of the other environmental aspects of fluidized-bed combustion such as trace element emissions are discussed under the appropriate section of part 4.

Gas turbine cycles of the future, designed to burn coal-derived low-Btu gas or liquid fuel, will have relatively low emission of sulfur dioxide and particulates. This is so since most of these contaminants are removed before reaching the turbine to protect it from corrosion and erosion.

The high temperature combustion used in these future combustors could increase nitrogen oxide formation above that of contemporary turbines. NO_x from the open cycle gas turbine combustor would consist of thermal NO_x produced from conversion of atmospheric nitrogen) and fuel-bound NO_x (produced from conversion of fuel-bound nitrogen). Coal-derived liquid fuels are expected to produce higher emissions of NO_x than low-Btu gas, since the liquid fuels are more conducive to the formation of thermal NO_x and contain more fuel-bound NO_x (14).

The gas turbine combustor should emit negligible amounts of carbon monoxide and unburned hydrocarbons under full load operating conditions when combustor efficiency approaches 100 percent. However, for startup or partial load conditions, the combustor efficiency would decrease, increasing emissions of CO and HC. Some unburned carbon particles also may be emitted under partial load conditions, but under normal, full load conditions, all the carbon should be combusted.

Particulate emissions from open cycle gas turbines should not be a problem since removal of the particulates from the combustion gases to levels well below environmental standards is necessary to prevent erosion of the turbine blades, walls, and ducting system. If the turbine erosion does occur, erosion products could present a potential emission problem. Trace elements such as nickel, chromium, cobalt, and molybdenum may be generated from the erosion of turbine materials, ceramic coating, and refractory composites, and from the fuel itself.

Liquid Effluents and Solid Waste

As stated above, contemporary gas-steam turbine combined cycle power plants consuming light distillate oil or natural gas have no liquid or solid waste of any consequence. However, for those combined cycle configurations involving fluidized-bed, low-Btu gasification, or coal liquefaction, the environmental problems attributed to liquid or solid effluents are those associated with the particular process rather than its application in a combined cycle power generation scheme. Therefore, the reader is referred to the appropriate sections within this publication where such environmental aspects are discussed for the specific process.

4.5 Performance

Current

In the days of "cheap" gas and oil, a gas turbine with its relatively low initial cost and short delivery was the natural choice for generating power at small dispersed stations, meeting peak loads at larger centralized utility plants, and in many cases, for base load service. Today, the initial cost is still relatively low and the delivery time the best of any comparable rated equipment.

A typical gas turbine-generator currently being produced converts approximately 30 percent of the fuel input energy into electrical power. Combined cycle concepts have received attention as a means of utilizing turbine waste heat to produce additional electric energy thereby providing greater overall system efficiencies. Current operating combined cycle plants typically have efficiency values on the order of 40 percent. Unfortunately, existing combined cycle plants depend on clean petroleum based fuels.

Projected

As stated above, current combined cycle power plants are reasonably efficient and environmentally safe performers. Unfortunately, such performance depends upon clean fuels whose price and availability lack the stability on which to base a reliable electric power generating industry. Therefore, although promising, the future for combined cycle systems is limited by many technological hurdles now under intense research and development. These R&D areas being sponsored by EPA, DOE, industry, and others include: 1) advances in high-temperature (2500-3000°F) gas turbine design; 2) development of improved gas turbine construction to withstand hot, corrosive and erosive particulate gases from low-grade fuels; 3) commercialization of economically viable processes to convert coal to a suitable liquid or gaseous fuel; 4) hot gas cleanup of particulates; 5) perfection of fluidized-bed combustion applicable to utility sized plants; and 6) implementation of advanced power systems such as fuel cells and MHD. The first five of these areas are essentially directed at solving the fuel problem faced by contemporary combined cycle power plants. As achievements are realized, a second generation of combined cycle plants will evolve which will be capable of efficiencies comparable (40+%) or greater than present systems, but more importantly, will not rely on scarce clean fuels. The advanced concepts like fuel cells and MHD represent an entirely different topping cycle concept which, as discussed in their respective sections, when combined with a steam bottoming cycle, offers the prospect for coal-to-electricity efficiency levels of near 50 percent. However, as a practical combined cycle technology, these concepts are not anticipated to be implemented until the near 2000 period and are therefore not considered in further detail.

In the area of turbine technology, work sponsored by DOE and others is directed at the development of gas turbines which can operate efficiently on lower grade, more readily available fuels. Prime candidates for use in the near term are residual oils and fuels made from agricultural and urban waste products. In the longer run, these fuels will be replaced by the synthetic fuels that should eventually be derived from coal and oil shale. Because many different liquefaction, gasification, and other fuel-cleanup processes are being developed, future turbines must have the capability to burn a broad spectrum of fuels with a wide range of contaminant levels (12). Such lower grade fuels burn hotter and contain more contaminants than do light distillate oil and natural gas. To cope with this, improved turbine combustors and blades are being developed which can withstand the hot, corrosive gases resulting from these lower grade fuels. Other gas turbine development efforts are focused on improved cooling systems intended to increase turbine durability when hot-burning fuels are used. One method of this type involves fabricating the turbine blades with internal channels to carry cooling fluid.

When synthetic liquid and gaseous fuels become commercially available and advanced turbine technology permits inlet temperatures in the 2500-3000°F range, then we will see combined cycle electric generating efficiencies of over 50 percent based upon the heating value of the clean fuel as delivered (1). The inefficiency of an off-site fuel plant for conversion of the coal to a clean fuel would reduce the coal-to-electricity efficiency level to approximately 40 percent. It is these energy losses attributed to coal conversion that create strong incentives to design more efficient gas turbines and to use them in combined cycle systems for base load and intermediate service. If an integrated low-Btu gasifier configuration of the type discussed earlier were employed as the fuel supply system and comparable gas turbine inlet temperature (2500-3000°F) were acceptable, coal-to-electricity efficiencies could reach 44 percent.

The gas-steam turbine combined cycle configurations using the pressurized fluidized-bed combustor/boiler also would be capable of efficiencies close to 40 percent.

4.6 Economics

Current

When looking at the cost of contemporary combined cycle power plants versus conventional coal or nuclear facilities, one must not only address the initial plant cost, but also the price and availability of suitable environmentally acceptable fuels. As mentioned earlier, the gas-steam turbine combined cycle plants currently being offered by the industry have initial capital costs and lead times significantly less than those of alternate generating systems. For example, combined cycle plants fired by gas and/or oil have an initial capital cost of less than $400 per kilowatt and can be installed and operating in less than three years. This compares with a coal-fired steam plant cost with FGD of about $850 per kilowatt taking five to ten years to plan and build and a nuclear facility cost of $1,100 or more per kilowatt requiring 10 to 13 years lead time (3). However, this is just the "tip of the iceberg." In spite of this low capital cost and reasonable efficiency (40+%), the cost of electricity generated by contemporary combined cycle systems approaches 40 mills per kilowatt hour based upon today's clean fuel prices ($3.00 per MBtu for natural gas), as compared to around 30 mills/kwh for a coal-fired steam plant with FGD. If the quality of fuel was reduced, savings realized would be more than offset by the increased overhaul and maintenance cost. The poorer the fuel, the lower the turbine reliability, the more frequent the overhaul, and thus, the greater the operating costs. When running on distillate oil, a gas turbine can last 30,000 to 50,000 hours before overhaul and when natural gas is used, this period is doubled. However, when today's gas turbines are run on the more abundant residual fuels, turbine life can be as short as 2000 to 5000 hours before overhaul is necessary (3).

Projected

As noted earlier, the term combined cycle covers a broad range of systems comprised of cycles having well established technologies as well as those barely beyond the conceptual stage. In these latter cases, since there are so many uncertainties with respect to the point of eventual implementation, equipment costs, and environmental regulations, the overall economics of these systems remain to be established with reasonable certainty. For example, projections have been made that electricity generated by MHD combined cycle systems will cost about 32 mills per kilowatt hour in the 1990's as compared to 45 mills/kwh from conventional coal-fired plants at that time (15). Needless to say, the accuracy of such an estimate is subject to many poorly defined technical, environmental, and economic issues. However, with the more established technologies that have near term prospects, the economics are better defined. These are mainly contingent upon achieving improved heat rates with high temperature turbines capable of withstanding the corrosive gases from burning low grade synthetic and natural fuels. Obviously, the overall economics are further sensitive to the ultimate costs of such equipment and fuels. It is safe to say that the coming generation (early 1980's) of gas-steam turbine combined cycle plants will achieve heat rates below 8000 Btu per kilowatt hour. At a clean fuel (e.g., natural gas) cost of $3.00 per MBtu and a plant cost of $400/kW, the cost per kilowatt hour from a 320 megawatt power station will be over 38 mills per kwh.

This is based upon an 18 percent per year capital charge and the plant functioning in a base load capacity (5000+ hours per year). Even though this projected plant is over 40 percent efficient, its cost, in terms of current dollars, is high because of the clean fuel cost. Therefore, as the various synthetic fuel processes evolve, they will essentially dictate whether the combined cycle is an economic alternative.

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12. R&D Aimed at Burning Coal-Derived Fuels. Power, November 1977.

13. For Higher Efficiency...Look to the Combined Cycle. Turbomachinery International, September 1978.

14. U.S. Department of Energy. Environmental Development Plan (EDP) - Advanced Power Systems Program. Assistant Secretary for Environment, DOE/EDP-0021, Washington, D.C., March 1978.

15. MHD's Target: Payoff by 2000. IEEE Spectrum, May 1978. pp. 46-51.

5. Low/Medium-Btu Gasification

5.1 Overview

No fixed energy values are associated with the definition of low and medium-Btu gases. However, 100 to 200 Btu's per cubic foot is generally considered low and 300 to 650 Btu's is generally considered medium (1). The low/medium-Btu gasification of coal is essentially an existing technology. In fact, gas was first manufactured from coal in the eighteenth century. Currently, low/medium-Btu coal gasifiers are in use in Europe, South Africa, and to a very limited extent, in the United States.

Coal can be gasified by any of several processes: synthesis, pyrolysis, and hydrogasification. In synthesis, coal or char is reacted with steam and oxygen and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In this process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form a methane product.

A number of low/medium-Btu coal conversion processes have been investigated. The U. S. Department of Energy, together with the Electric Power Research Institute and others, are sponsoring the development of several advance conversion processes, two of these being the Lurgi and the Koppers-Totzek. In addition, the U. S. Department of Energy is supporting efforts relating to the in situ gasification of coal.

Environmental problems common to coal associated energy generating systems will generally also apply to coal gasification facilities. Additional adverse environmental aspects of proven and pilot plant stage processes are difficult to assess because of the very limited data available from such operations.

The conversion efficiency as based on total energy input is somewhat process and site specific and is estimated to be in the 70 to 80 percent range including raw gas cleanup. The value without gas cleanup (i.e., raw hot gas output) is estimated to be as high as 90+ percent when the sensible heat of the gas is included. Since this is basically a developed technology, efficiencies are not expected to improve significantly over the foreseeable future.

Estimates of the cost of low/medium-Btu gas depend on many factors including utility or private financing, coal cost, effluent disposal requirements, etc. Current estimates range between $2.50 and $4.00 per million Btu for low-Btu gas and $5.00 to $8.00 for medium-Btu gas.

5.2 Process Description

Current

Figure 15 is a generalized diagram that shows the basic processing steps common to different types of gasification processes. An overview of the overall process consistent with the figure follows.

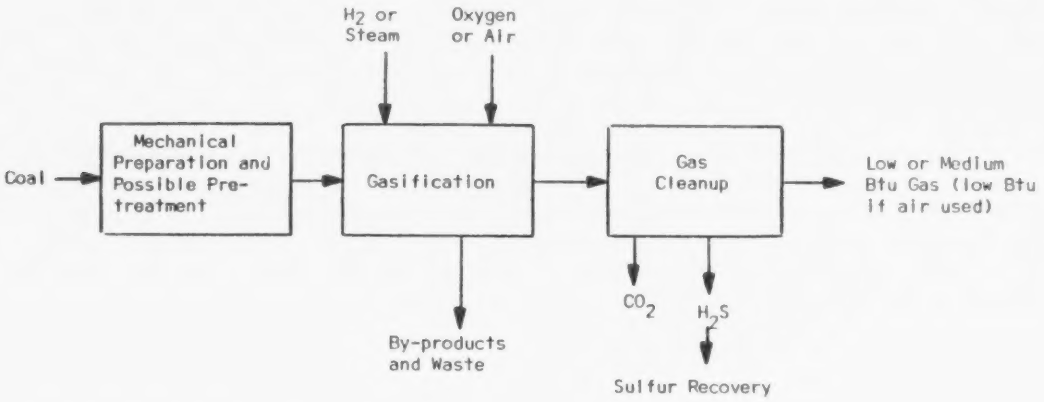
H2 or Steam
Oxygen or Air
Coal
Mechanical Preparation and Possible Pre-treatment
Gasification
Gas Cleanup
Low or Medium Btu Gas (low Btu if air used)
By-products and Waste
CO2
H2S
Sulfur Recovery

Figure 15

Generalized Flow Diagram - Low/Medium-Btu Gas

The first step, coal preparation with possible pretreatment, can be simple or complex depending on the characteristics of the specific gasification process. This step can range from crushing or grinding to proper size to more sophisticated preparation including sizing, physical beneficiation, and drying. In addition, in certain processes, it may be necessary to pretreat an agglomerating coal feed to destroy the coking properties (1, 2).

The three primary ingredients needed to chemically synthesize gas from coal are carbon, hydrogen, and oxygen. Coal provides the carbon; steam is the most commonly used source of hydrogen, although hydrogen is sometimes introduced directly from an external source; and oxygen is usually supplied as either air or pure oxygen. Heat can be supplied either directly by combusting coal and oxygen inside the gasifier or from an external source (1).

Coal can be gasified by any of several processes: synthesis, pyrolysis, or hydrogasification. In synthesis, coal or char is reacted with steam and oxygen and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In the process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form methane.

Three combustible gases produced by coal gasification processes are carbon monoxide (CO), methane (CH_4) and hydrogen (H_2). Methane, the primary component of natural gas, is similar to natural gas in heating value. Carbon monoxide and hydrogen heating values are approximately equal, being about one-third the methane/natural gas value. Several noncombustible gases are also produced, including carbon dioxide, hydrogen sulfide, and nitrogen (1).

Gas manufactured from coal was first produced in the eighteenth century. More recently (i.e., last twenty years), a large number of gasifiers have been proposed and a number built and tested. It is possible to classify gasifiers by various means as indicated in references 1 and 2. These include: a) the method of contacting reactants, b) the gasifying medium, and c) the means of supplying heat.

Detail

The U. S. Department of Energy has been actively supporting the development of low, medium, and high-Btu gasification technology. Currently there are a number of commercially proven processes, a number of process development programs, and efforts relating to in situ gasification of coal. An overview of selected commercially available processes and processes under development follows.

Fixed Bed Gasifier--Lurgi (1)

Only noncaking coals can be used in this process. As indicated in Figure 16, pulverized coal is introduced into a pressurized reactor vessel through a lock hopper. The coal passes downward and is distributed onto a rotating grate. Steam and oxygen are introduced below the grate. All coal is combusted, leaving only ash which is allowed to fall through the grate. Product gas from the combustion zone above the grate leaves the reactor at 800 to 1000°F. A single 12 foot diameter gasifier section in a commercial plant would produce approximately 10 million scf/day. Typical gasifier section outlet composition is approximately (3):

Gas	Mol. % (dry)
CH_4	10
H_2	38
CO	24
CO_2	28

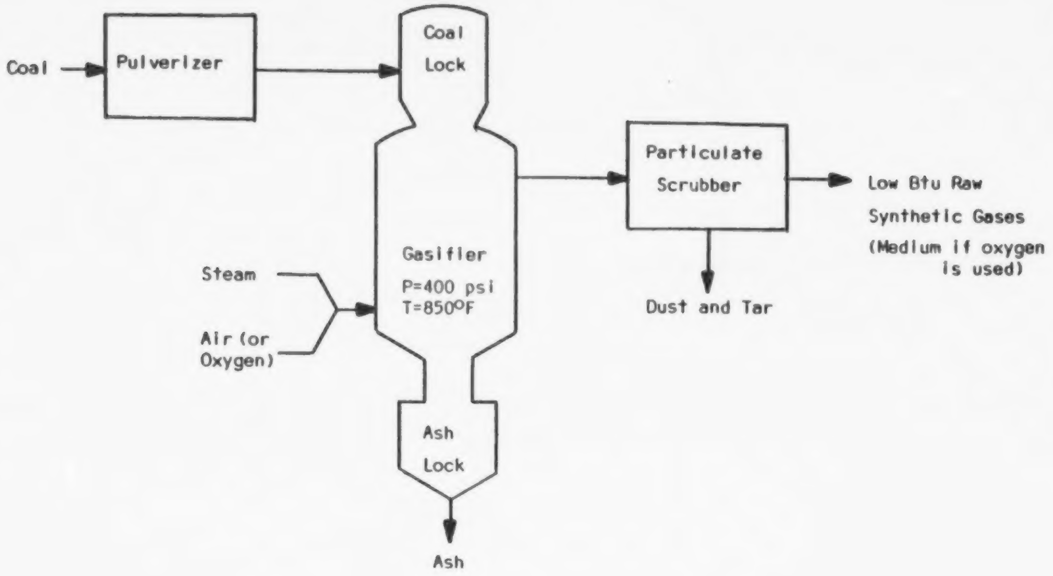
Coal
Pulverizer
Coal
Lock
Gasifier
P=400 psi
T=850°F
Steam
Air (or
Oxygen)
Ash
Lock
Ash
Particulate
Scrubber
Dust and Tar
Low Btu Raw
Synthetic Gases
(Medium if oxygen
is used)

Figure 16

Lurgi Low-Btu Coal Gasification Process

Entrained Gasifier--Koppers-Totzek (1)

For this process, finely ground coal is mixed with oxygen and steam and then pumped into an atmospheric-pressure vessel (see Figure 17). Because of the low pressure used and the entrained flow of the material injected, a complex system of hoppers is avoided. Combustion occurs at high temperatures (about 3000°F) in the center of the reactor vessel and the product gas exits upwards through a central vertical outlet. A typical large gasifier is about 10 feet in diameter and 25 feet long. A single Kopper-Totzek reactor will produce about twice the gas of a Lurgi reactor. Typical gasifier section outlet composition is approximately (2, 3):

Gas	Mol. % (dry)
H_2	36
CO	56
CO_2	6
N_2	2

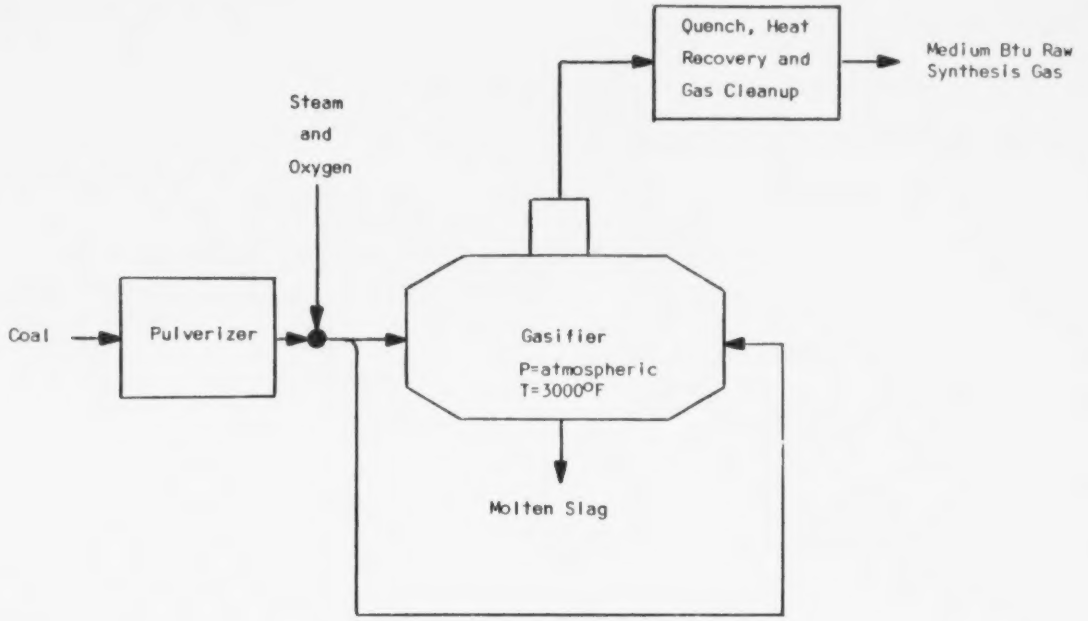

Figure 17

Koppers-Totzek Coal Gasification Process

U. S. Department of Energy Supported R&D Efforts

Westinghouse Coal Gasification Effort (4)

In this process, coal is crushed to a topsize of 6 mesh, dried, and transported to a reactor vessel for devolatilization and partial hydrogasification (see Figure 18). A central draft tube is used primarily for recirculating solids. Recycled solids required to dilute the feed coal and temper the hot inlet gases flow downward in the fluidized bed surrounding the draft tube. The fluidizing agent is a portion of the gases entering the unit. Recirculating solids have flow rates up to 60 times the coal feed rate to prevent the agglomeration of the feed coal as it devolatilizes and passes through the plastic or sticky phase. Dense, dry char collects in the fluidized bed at the top of the draft tube and is withdrawn at this point. Dolomite or calcium oxide (sorbent) may be added to the fluidized bed to absorb the sulfur present as hydrogen sulfide in the fuel gas. Spent sorbent could be withdrawn from the bottom of the reactor and regenerated. Heat for devolatilization is supplied primarily by the high-temperature fuel gas produced in the gasifier-combustor. After separation of fines and ash, product gas is cooled and scrubbed with water for final purification.

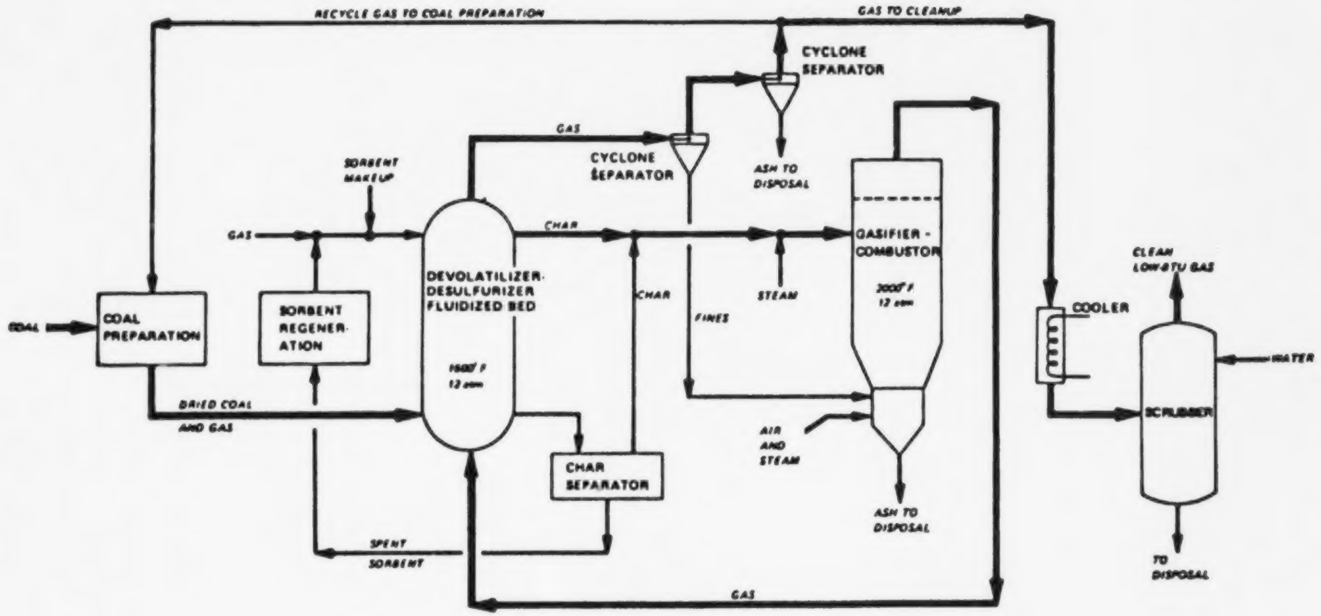
RECYCLE GAS TO COAL PREPARATION
GAS TO CLEANUP
CYCLONE SEPARATOR
GAS
CYCLONE SEPARATOR
ASH TO DISPOSAL
SORBENT MAKEUP
GAS
COAL
COAL PREPARATION
SORBENT REGENERATION
DEVOLATILIZER-DESULFURIZER FLUIDIZED BED
1600° F
12 atm
CHAR
CHAR
FINES
STEAM
GASIFIER-COMBUSTOR
2000° F
12 atm
COOLER
CLEAN LOW-BTU GAS
WATER
SCRUBBER
DRIED COAL AND GAS
CHAR SEPARATOR
AIR AND STEAM
ASH TO DISPOSAL
TO DISPOSAL
SPENT SORBENT
GAS

Figure 18

Westinghouse Electric Corp. Low-Btu Gasification of Coal Process

Final gasification occurs in a fluidized bed gasifier combustor. Char from the devolatilizer is burned with air in the lower leg of the gasifier at 1900-2000°F to provide the heat for gasification. Heat is transported from the combustor to the gasification zone by combustion gases flowing upward and by char circulating between the combustion and gasification zones. Ash from combustion of fines agglomerates on the ash from the char and segregates in the lower bed leg for removal.

Combustion Engineering Entrained Gasifier (4)

The Combustion Engineering gasification process is based on an air-blown, atmospheric-pressure, entrained-bed gasifier. A schematic of the process is provided in Figure 19. In the process, a portion of the pulverized coal and recycled char are fed to the combustion section of the gasifier and burned to supply the heat necessary for the endothermic gasification reaction. In the combustion section, nearly all of the ash in the system is converted to molten slag, which is then drawn off the bottom of the gasifier. The remainder of the pulverized coal is fed to the reduction portion of the gasifier where it is contacted with hot gases entering the reduction zone from the combustor. The gasification process takes place in the entrainment portion of the reactor where the coal is devolatilized and reacts with the hot gases to produce the desired product gas. This 1700°F product gas is then cooled to 300°F. At this point, the gas contains solid particles and hydrogen sulfide that must be removed. Solids are removed and recycled by means of a spray drier, cyclone separators, and venturi scrubbers. Hydrogen sulfide is removed and elemental sulfur is produced by the Stretford process. The clean low-Btu gas (about 120 Btu per standard cubic foot) can then be delivered to the burners of power boilers, gas turbines, or combinations of the two in a combined-cycle power generator.

Operating conditions will have a variety of effects on the cost and quality of the gas produced in this system. For example, oxygen could be substituted for air in the gasifier combustor, thereby increasing the heating value of the product gas from 120 to 285 Btu per standard cubic foot. Conversely, this change will also increase the cost of producing the gas, depending on the price of oxygen and the quantity used.

Underground Gasification

A very substantial portion of our underground coal resources is not expected to become economically recoverable by conventional mining methods in the foreseeable future. Underground coal conversion would permit the recovery of some of this so-called unmineable coal by converting it in place to a gaseous fuel that could be extracted, cleaned and possibly upgraded prior to use.

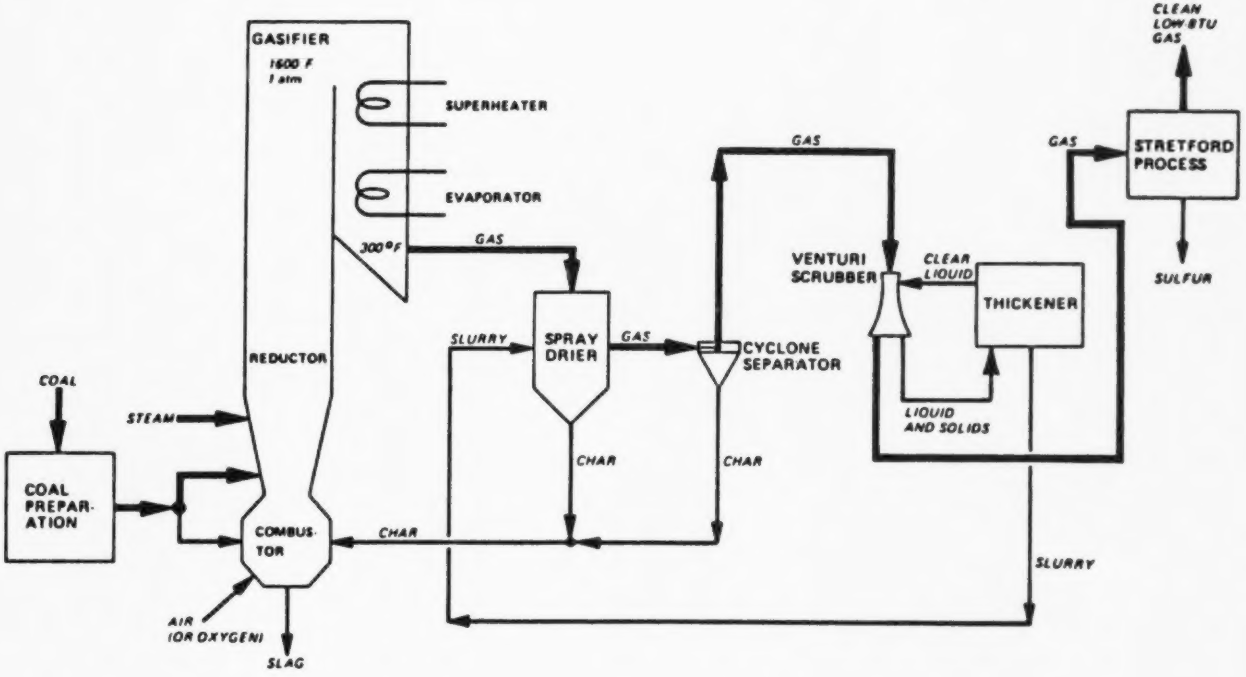
GASIFIER
1600 F
1 atm
SUPERHEATER
EVAPORATOR
300°F
GAS
REDUCTOR
COAL
STEAM
COAL PREPARATION
COMBUSTOR
CHAR
AIR (OR OXYGEN)
SLAG
SLURRY
SPRAY DRIER
GAS
CHAR
CYCLONE SEPARATOR
CHAR
GAS
VENTURI SCRUBBER
CLEAR LIQUID
THICKENER
LIQUID AND SOLIDS
SLURRY
GAS
STRETFORD PROCESS
CLEAN LOW-BTU GAS
SULFUR

Figure 19

Combustion Engineering, Inc. Low-Btu Gasification of Coal Process

The concept of converting coal into fuel gas in the ground or "in situ" is an old concept. The idea was first suggested by the British in 1868 and by the Russians in 1888. These two countries have conducted the largest efforts to date. Underground gasification of coal has been tested in the Soviet Union since the early 1930's. Major projects were undertaken in the early 1950's and reached a peak in the late 1960's. The Soviets now have three underground gas plants in operation. It should be noted that only a very small amount of the energy needs of the U.S.S.R. are supplied by this technology (2, 5).

Large scale experiments were conducted by the British from 1949 to 1959. Following World War II, Belgium, Morocco, the United States and Germany have committed resources to underground gasification programs (2, 5).

Coal is gasified underground by drilling boreholes in the seam and injecting air (or oxygen) and steam into the underground reaction zones. The hot gases are forced through the seam to the exit borehole and are carried to the surface, where they are cleaned and upgraded for use (5).

There are a number of identified potential disadvantages associated with underground coal gasification. These include (5):

- Possibility of being unreliable or uneconomical due to uncertainties in underground conditions,
- Possible disruption of aquifers and pollution of groundwater,
- Ground subsidence that could cause gas leakage or damage to surface equipment, and
- Low-Btu gas (from air injection) is uneconomical to transport over long distances; thus markets for this gas must be near the plant site.

Changes in groundwater quality and the possible effects of subsidence and ground movement introduced by the underground gasification cavity represent significant environmental concerns associated with in situ gasification process. Measurement by the Lawrence Livermore Laboratory of gasification experiments indicate that the reaction products, such as ash and some coal tars that remain underground following gasification are a potential source of localized groundwater contamination. The concentration of important contaminants, such as phenols, shows a significant decrease due to absorption by the surrounding coal. There is also concern relating to roof collapse connecting the gasification cavity with overlying aquifers. It is quite conceivable that hydrogeological site selection criteria may be of considerable environmental importance in choosing commercial-scale operations (6).

In summary, there is substantial uncertainty as to the environmental aspects of a large in situ coal gasification complex. The technology as applied to domestic coal resources is still in the R&D stage. The potential, including associated economics, has not been adequately assessed.

As previously indicated, a number of gasification processes have or are currently receiving R&D support from the Department of Energy. One such process previously discussed is the Combustion Engineering Entrained Gasifier. When air is used as the oxidant, the produced fuel gas is in the low-Btu category and has the economic advantage of not requiring an air separation plant. When an oxygen blown device is used the fuel gas will be in the range considered as medium-Btu. Reference 7 contains projected heat balances for both a commercial scale air blown (low-Btu) gasifier and an oxygen blown (medium-Btu) gasifier. An estimated heat balance (based on reference 7) for an air blown gasifier is given in Table 14. Diagrammatically, this is illustrated by the heat flow diagram, Figure 20. Table 15, also based on reference 7, provides a heat balance for an oxygen blown gasifier. Diagrammatically, this can be illustrated by Figure 21. The heat balances are based on plants gasifying 10,000 standard tons of Illinois No. 6 coal a day. The Btu values per standard cubic foot of gas as indicated by reference 4 are within 10 percent of the values indicated by reference 7.

5.3 Applications

Current

Currently, according to the U. S. DOE, there are several commercial users of low-Btu gas and no medium-Btu commercial plants in the United States. This is the case even though low/medium-Btu gasification of coal can be considered an existing technology.

Projected

The significant utilization of low/medium-Btu gas derived from coal basically depends on the overall economics (including environmental control) as compared to other options. In this regard, DOE is currently providing support to industry and other potential users of low-Btu gas in order to accumulate and analyze technical and economic data on operating systems, and to decrease the near-term consumption of natural gas and fuel oil.

Six proposals were selected including four that would employ available fixed-bed gasifiers. EPA is supporting the environmental assessment for each demonstration project in the overall DOE supported program.

In essence, the significant use of a low or medium-Btu gas derived from coal is uncertain. We currently have the technical capability and yet the current use is insignificant.

Table 14

Estimated Heat Balance for Commercial Scale Low-Btu Gasification Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
System Output		
Product gas heating value	6,919	67.86
Product gas sensible heat	817	8.01
Export power (at 3414 Btu/kwh)	382	3.75
System Losses		
Product gas latent heat	243	2.38
Ash combustibles and sensible heat	85	0.83
Gasifier radiation loss	153	1.50
Sulfur product heating value	102	1.00
Steam turbine condenser (latent heat)	965*	9.46
Isobutane condenser (latent heat)	80	0.79
Blower driver condenser (latent heat)	201	1.97
Stretford miscellaneous (sensible and latent heat)	179	1.76
Coal pulverizer	94	0.92
Sensible and latent heat capture (blower air, etc.)	(76)	(0.74)
Other miscellaneous	52	0.51
Energy Input		
Coal heating value	10,196	100.0

* Approximately 65% of total associated with export power

Coal Input - Illinois No. 6; 10,000 ST/day; 12,235 Btu/lb; Sulfur 4.29% (by wt.)

Gas Output - 113 Btu/scf heating value (not including sensible heat)

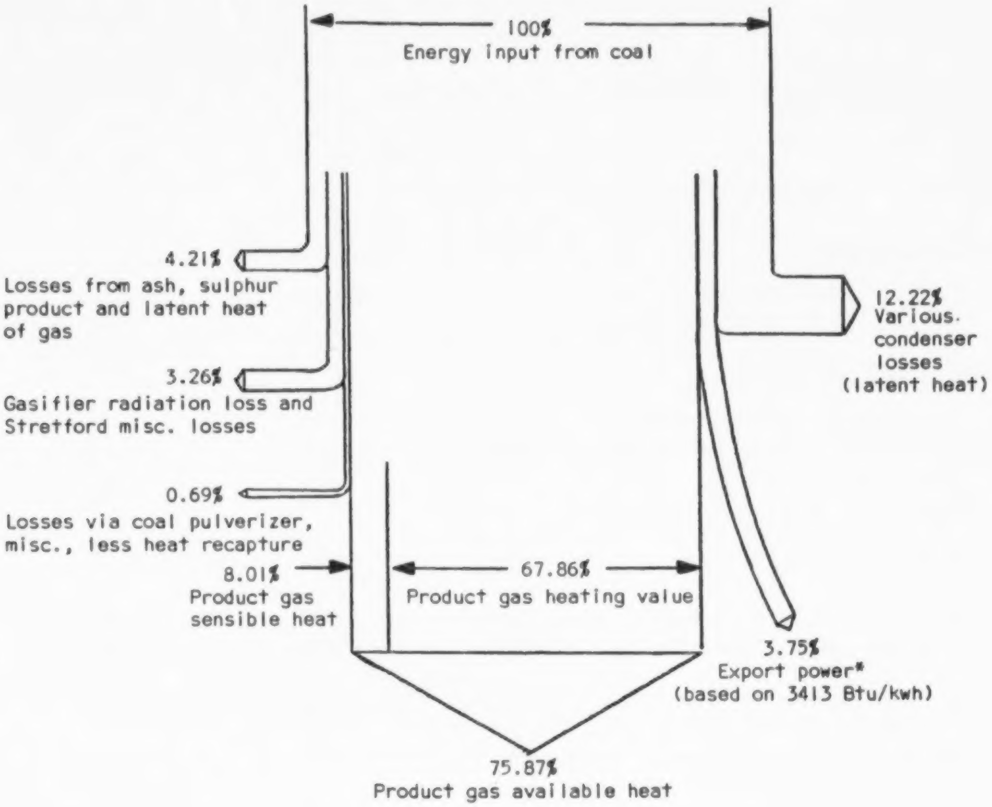
100%
Energy input from coal
4.21%
Losses from ash, sulphur product and latent heat of gas
3.26%
Gasifier radiation loss and Stretford misc. losses
0.69%
Losses via coal pulverizer, misc., less heat recapture
8.01%
Product gas sensible heat
67.86%
Product gas heating value
12.22%
Various condenser losses (latent heat)
3.75%
Export power*
(based on 3413 Btu/kwh)
75.87%
Product gas available heat

Figure 20

Heat Flow Diagram for Low-Btu Gasification Plant

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* If export power is calulated on the basis of 9000 Btu/kwh (the energy required to generate the equivalent output), the system efficiency is 85.75% (vs. 79.62%) (i.e., for product gas heating and sensible heat values plus electrical energy based on Btu's required to produce equivalent electrical energy).

Table 15

Estimated Heat Balance for Commercial Scale
Medium-Btu Gasification Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
System Output		
Product gas heating value	8,020	78.40
Product gas sensible heat	185	1.81
System Losses		
Product gas latent heat	139	1.36
Ash combustibles and sensible heat	85	0.83
Gasifier radiation loss	153	1.49
Sulfur product heating value	102	1.00
Steam turbine condenser (latent heat)	70	0.68
Compressor driver condenser (latent heat)	800	7.82
Blower driver condenser (latent heat)	42	0.41
Air compressor intercooler (sensible heat)	213	2.08
Air compressor aftercooler (sensible heat)	189	1.85
Stretford miscellaneous (sensible and latent heat)	179	1.75
Coal pulverizer (sensible and latent heat)	94	0.92
Sensible and latent heat capture (compressor suction air, etc.)	(77)	(0.75)
Other miscellaneous	36	0.35
Energy Input		
Coal heating value	10,196	99.67
Electric power (at 3414 Btu/kwh)	34	0.33
Total Input	10,230	100.0

Coal Input - Illinois No. 6; 101,000 ST/day; 12,235 Btu/lb; Sulfur 4.29% (by wt.)

Gas Output - 312 Btu/scf heating value (not including sensible heat)

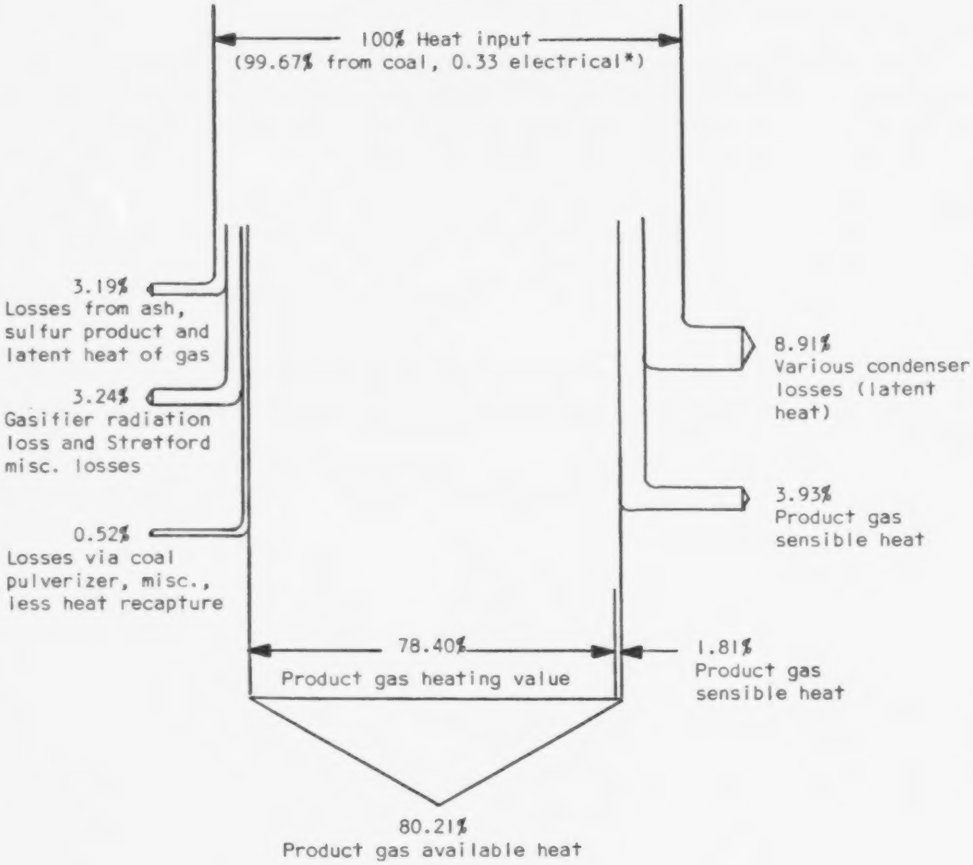
100% Heat input
(99.67% from coal, 0.33 electrical*)
3.19%
Losses from ash, sulfur product and latent heat of gas
3.24%
Gasifier radiation loss and Stretford misc. losses
0.52%
Losses via coal pulverizer, misc., less heat recapture
8.91%
Various condenser losses (latent heat)
3.93%
Product gas sensible heat
78.40%
Product gas heating value
1.81%
Product gas sensible heat
80.21%
Product gas available heat

Figure 21

Heat Flow Diagram for Medium-Btu Gasification Plant

---

* Electrical input based on 3413 Btu/kwh

5.4 Environmental Considerations

Identified Pollutants

This discussion does not cover coal extraction and transportation. Reference 2 indicates that the data base for evaluating environmental, health and safety aspects is very limited and reported information is frequently contradictory. This same reference also indicates that adverse health effects expected are particularly difficult to estimate because operational experience is so limited. The provided material, based mainly on analyses and very limited actual data, are derived from the indicated referenced sources.

Air Emissions

The type and sources of potential air pollutants from coal conversion are as follows (8):

Pollutant	Process-Generated	Combustion-Generated
Particulate matter	X	X
Sulfur oxides	X	X
Reduced sulfur compounds	X	
Nitrogen oxides		X
Hydrocarbons	X	X
Carbon monoxide	X	X
Trace metals	X	X
Odors	X	
Other gases (including NH_3, HCN, HCl)	X	

Sulfur dioxide is emitted principally from the tailgas stream of the sulfur recovery plant and from stack gases of auxiliary systems requiring fuel oxidation. These include plant boilerhouse and miscellaneous fossil fuel fired process heaters.

Particulate matter can be released as a fugitive dust and as a process or combustion-based stack emission. Fugitive emissions have a potential for occurring at receiving, handling, and storage areas for coal, solid waste, and from leakage from process equipment elements. Process stack emissions would include the exhaust of pollution control equipment (e.g. scrubbers and precipitators). Fuel combustion would provide the potential source of particulate matter.

Nitrogen oxide emissions would result from fossil fuel firing of boilers. Hydrocarbon emissions could occur from liquid storage areas, system leaks, and from the evaporation of hydrocarbon liquids dissolved in cooling systems. Reduced sulfur compounds occur in the initial product stream of virtually all coal conversion processes.

Trace element emissions of such substances as mercury, beryllium, arsenic, and other heavy metals which are contained in coal in small amounts are expected in view of experience from coal fired boilers. In addition, other gaseous emissions, especially hydrogen cyanide and ammonia (as well as hydrogen chloride and gaseous odorants) may also be associated with coal conversion plants.

Liquid Effluents

Waste waters from coal conversion processes can originate from a number of sources. These include water of constitution, water added for stoichiometric process requirements, and water induced for gas scrubbing and by-product recovery. Such process waters come into contact with contaminants in coal and are likely to be a principal source of potential pollution.

There are potential sources of water effluents from boiler blowdown, the raw gas cooling system, and overfill of water clarifiers. It is expected that blowdown and raw gas cooling waters will be recycled via a clarifier and filter system for reuse. It has been estimated (i.e., for the Koppers-Totzek process) that 1.3 million gallons will be produced for every 10^{12} Btu's of coal input to the gasifiers. In addition, the clarifiers will require 80 gallons per minute in makeup water because of evaporation losses in quenching the ash from the gasifier (1).

Solid Wastes

The solid waste generated by low-Btu gasification ranges from 3,500 to 8,500 tons for each 10^{12} Btu's of coal input. The value is dependent on the heat and ash values of the coal. If the sulfur recovered in the process cannot be sold, it also will require disposal. The solid waste from the gasifier will resemble waste from coal cleaning and boiler plant operations. This waste (from a gasifier) contains small quantities of radioactive isotopes. Analyses for an agglomerating gasifier provided estimated levels of 0.00076 curie of radium-226 and 0.0128 curie of radium-228 and thorium-228 and 230 for each 10^{12} Btu coal input to the gasifiers (1).

Regulatory Impacts

The environmental aspects of gasification are, to an extent, site specific. Reference 2 indicates that potential air pollutants are similar in nature to those of a power plant and generally the same pollution control applies. Waste water pollution control would have to be tailored to the specific gasification process. Disposal of solids would have to take into account the potential for leaching and special treatment may be required prior to burial.

Currently, there is a substantial body of legislation that directly relates to the gasification of coal. There are Federal and state emission standards covering air, water and solid waste. There exists legislation and regulations covering toxic substances, safe drinking water, occupational health and safety, protection of fish and wildlife and others. Any viable conversion technology would necessarily have to be consistent with the substantial body of environmental, health and safety legislation and regulations in being.

5.5 Performance

Current

In the March 15, 1979, issue of the Commerce Business Daily, the U. S. Department of Energy stated as part of a procurement statement: "Processes for producing environmentally acceptable gas from coal are available commercially. Although there are numerous low and medium-Btu gasification plants operating overseas, there are only two commercial users of low-Btu coal gas and no medium-Btu commercial plants in this country today. Uncertainty of costs, operating reliability and retrofit impacts; effect of gas on product quality and plant processes; plant siting and environmental factors; gas distribution costs and safety; regulatory impacts; coal supply and transportation; capital/financing arrangements, etc., are considerations which a potential owner/user must weigh when seriously considering the use of low and/or medium-Btu coal gas as an alternative fuel option. The lack of commercial operating experience in this country from which answers to many of those questions can be readily obtained, in combination with the availability of cheaper fuels today, removes any strong motivation by industry to assess in-depth the utilization of low and medium-Btu gas from coal."

In essence, the technology exists and is proven. However, there is little domestic operating experience to go on. In addition, it should be noted that there appears to be a very limited number of situations where use of a low or medium-Btu gas obtained from coal would be more attractive than the direct use of coal. This has been somewhat indicated by conversion assessments of industrial boiler plants and industrial operations and the low demand for gasification facilities.

The conversion efficiency as based on total energy input is somewhat process and site specific and is estimated to be in the 70 to 80 percent range including raw gas cleanup. The value without gas cleanup (i.e., raw hot gas output) is estimated to be as high as 90+ percent when the sensible heat of the gas is included (2, 9).

Projected

This process, for all practical purposes, is a developed technology. Projected performance is not expected to improve significantly over present capabilities during the foreseeable future.

5.6 Economics

Current

We do not have an operating history to go on. Estimates of the cost of low/medium Btu gas depend on many factors including utility or private financing, coal cost, effluent disposal requirements, etc. Current estimates for low Btu gas range between $2.50 and $4.00 per million Btu (9). Medium Btu gas is estimated to range between $5.00 and $8.00 per million Btu. The range in price depends on many changing factors including raw coal cost, processing conditions, and pollution control requirements (9).

Projected

The projected price in terms of current dollars is expected to remain fairly stable. However, large escalation in the cost of coal could upset this expectation.

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6. Chemically Active Fluid Bed (CAFB)

6.1 Overview

The Chemically Active Fluid Bed (CAFB) process uses a shallow fluidized bed of lime or lime-like material to produce a clean, hot gaseous fuel from high sulfur feedstock (e.g., residual oil). A solid fuel feedstock such as coal is also feasible.

In applying the process to residual oil, oil is fed to a reactor that contains a fluidized bed of fine particles of limestone. The oil is vaporized in the reactor through a series of catalytic cracking and oxidation reactions. Sulfur values are released from the vaporized oil to be absorbed by the lime in the boiling limestone. The remaining hot, low-Btu, low sulfur fuel gas produced in the process is available for combustion (e.g., in a steam boiler).

The CAFB reactor contains two sections, one for gasification of the oil and one for regeneration of the limestone sorbent. In the regeneration step, sulfur dioxide is released from the limestone and is available for converting to elemental sulfur.

The initial CAFB pilot unit (2.39 MW) was developed by the Esso Research Centre in Abingdon, England. A 10 MW demonstration plant was subsequently constructed by Foster Wheeler at the La Palma Power Station (Central Power and Light Company) in San Benito, Texas.

Environmental data is very limited. Principal environmental concerns relate to the size of the particles in the product gas stream, the vanadium (bound in a mixture of oxides) emission level, and the disposal of spent, sulfided limestone. The solid waste disposal problem appears to be the major environmental concern.

Since all activities are R&D, no actual full-scale performance data is available. Even so, the total gasification efficiency is estimated to be approximately 85 percent. Similarly, economic values are also projections. EPA estimates that a retrofit CAFB plant to fuel a 500 MWe plant would cost $172 per kW of installed capacity (1977 dollars). The operating cost is estimated at 2 - 3 mills per kwh.

6.2 Process Description

Concept

The Chemically Active Fluid Bed (CAFB) process uses a shallow fluidized bed of lime or lime-like material to produce a clean, hot gaseous fuel from heavy high sulfur feedstocks, such as residual oils or refinery bottoms. Solid fuels, such as Texas lignite, have also been tested. The

CAFB performs three operations simultaneously: (1) gasification and/or cracking of the feedstock; (2) removal of sulfur; and (3) partial removal of vanadium and other metals. The sulfur, vanadium and other metals are captured by the chemically active fluid bed. The CAFB has operated at temperatures in the range of 870-920°C for that portion of the bed receiving the feedstock. This portion is commonly called the gasifier. The necessary heat release to maintain this temperature in this portion of the bed, or gasifier, is accomplished by partial combustion of the feedstock. Flue gas recycle has been used to control the bed temperature. The amount of air to the CAFB is about 20 percent of that required for complete combustion of the feedstock, and is varied from this percentage to match the attributes of the feedstock to the capabilities of the process (1).

As the feedstock is gasified, the sulfur is captured by the CAFB as calcium sulfide, because the reaction occurs in an oxygen deficient or reducing atmosphere. The bed material is then moved, via fluidization technique, to a regenerator section of the reaction vessel. In current practice, this regenerator section is separated from the gasifier portion by a refractory divider and has a separate plenum or air passage to supply air for the regeneration reaction. The regeneration reaction is accomplished by passing air through the fluid bed. The calcium sulfide in the bed is oxidized to sulfur dioxide and calcium oxide. A minor amount of calcium sulfate is also produced during the regeneration step. The heat required to sustain the regeneration reaction at about 1050°C is produced by the oxidation of the calcium sulfide, externally supplied coal, and from the oxidation of carbon deposited on the surface of the bed material. The gaseous stream from the regenerator contains 6 to 10 percent by volume of sulfur dioxide with 1 to 4 percent carbon dioxide and virtually no oxygen. This gas stream can be converted to either elemental sulfur or other products using existing technology (1).

The regenerated bed material is returned, via fluidized techniques, to the gasifier portion of the vessel and the cycle is repeated.

The clean, hot product low-Btu gas for the gasifier is ducted, through cyclones, to a boiler and burned in the normal manner, using burners designed specifically for the hot, low heating value product gas (1).

The process, as developed under U.S. Environmental Protection Agency sponsorship, operates at atmospheric pressure. Pressure differentials throughout the system are required to induce fuel and materials flow and are on the order of those found in conventional boiler installations (1).

Detail

The initial CAFB unit, a 2.39 MW pilot plant, was constructed at the Esso Research Centre, Abingdon, England facility. A 10 MW demonstration plant was subsequently constructed by the Foster Wheeler Energy Corporation (FWEC) at the La Palma Power Station of the Central Power and Light Company in San Benito, Texas (2).

Figure 22 is a generalized schematic diagram of the CAFB showing principal unit operations and material flows. Limestone and oil are fed continuously into the gasifier at a Ca (limestone)/S (oil) molar ratio of unity. Limestone ($CaCO_3$) is rapidly converted to lime (CaO) and CO_2 and the lime is maintained in a fluidized state by a preheated air/flue gas mixture. The air input rate is equal to roughly 20 percent of stoichiometric with respect to oil. Fuel oil is consecutively vaporized, oxidized, cracked and reduced at 870°C (1600°F) to produce a low-Btu gas. Over 80 percent of the input feed sulfur is removed by the lime. The gas travels from the gasifier through cyclones for particulate removal and then into a boiler for combustion. Lime is continuously cycled between the gasifier and the generator where the lime which is sulfided in the gasifier is oxidized to CaO. Approximately 7 percent of the input limestone as CaO is reduced to CaS on each pass through the gasifier. Sulfur dioxide produced in the regenerator is fed to a Foster Wheeler RESOX^{TM} unit where it is processed into elemental sulfur (2).

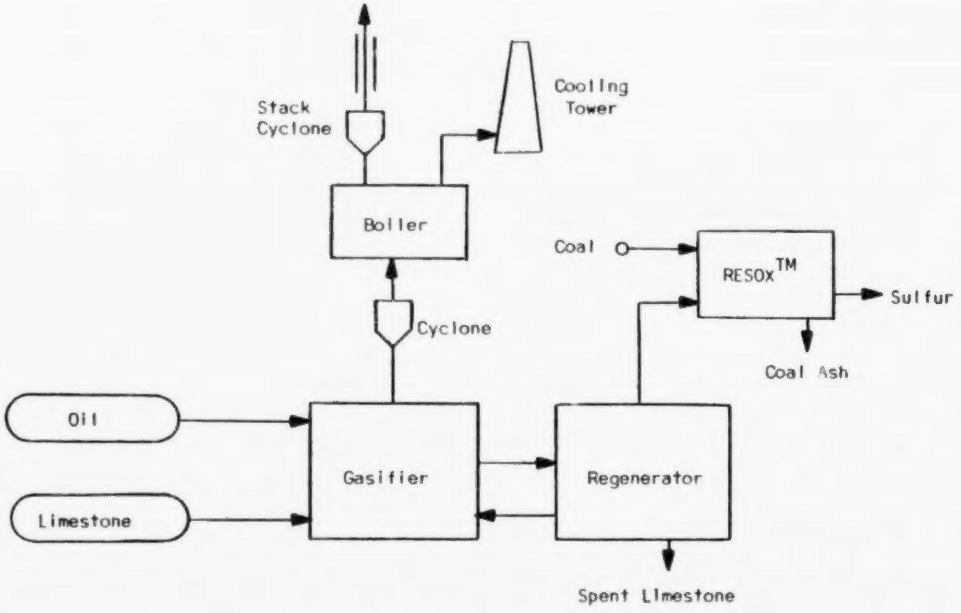

Figure 22

Generalized Schematic of the CAFB

The heat balance for a coal-fed CAFB plant nominally sized to fuel a 500 MWe steam-electric plant has been estimated based on data obtained from the existing pilot and demonstration plants. The provided heat balance information, Table 16, is based on a projected mass balance and related heat balance assessment obtained from reference 3. The heat balance is shown diagrammatically by Figure 23. It should be noted that Table 16 (and Figure 23) are projections for a commercial scale plant using Illinois No. 6 coal.

Table 16

Estimated Heat Balance for Coal Fed Commercial Scale CAFB Plant

	Btu/hour (10^6 Btu)	Percent of Total Energy Input
System Output		
Product gas heating value	4,364.15	75.17
Product gas sensible heat	690.85	11.90
System Losses		
Product gas latent heat	90.00	1.55
Gasifier radiation loss	112.36	1.94
RESOX associated radiation loss	4.67	0.08
Gasifier/regenerator sensible heat of ash and reacted limestone	35.09	0.60
Ash combustibles	56.00	0.97
Sulfur product heating value	78.23	1.35
Various latent heat, sensible heat and radiation losses (RESOX associated condensers, blowers, coolers, etc.)	374.06	6.44
Energy Input		
Coal heating value	5,617.78	96.77
Activated coal, coke and anthracite to RESOX unit	146.67	2.53
Electric power (at 3414 Btu/kwh)	40.96	0.70
Total Input	5,805.41	100.0

Nominally sized to fuel 500 MWe conventional steam electric plant

Coal input - Illinois No. 6; 520,743 pounds/hour; 10,788 Btu/lb; ash 9.6%, sulfur 3.9% (by wt.)

Note: RESOX^{TM} is a trademark

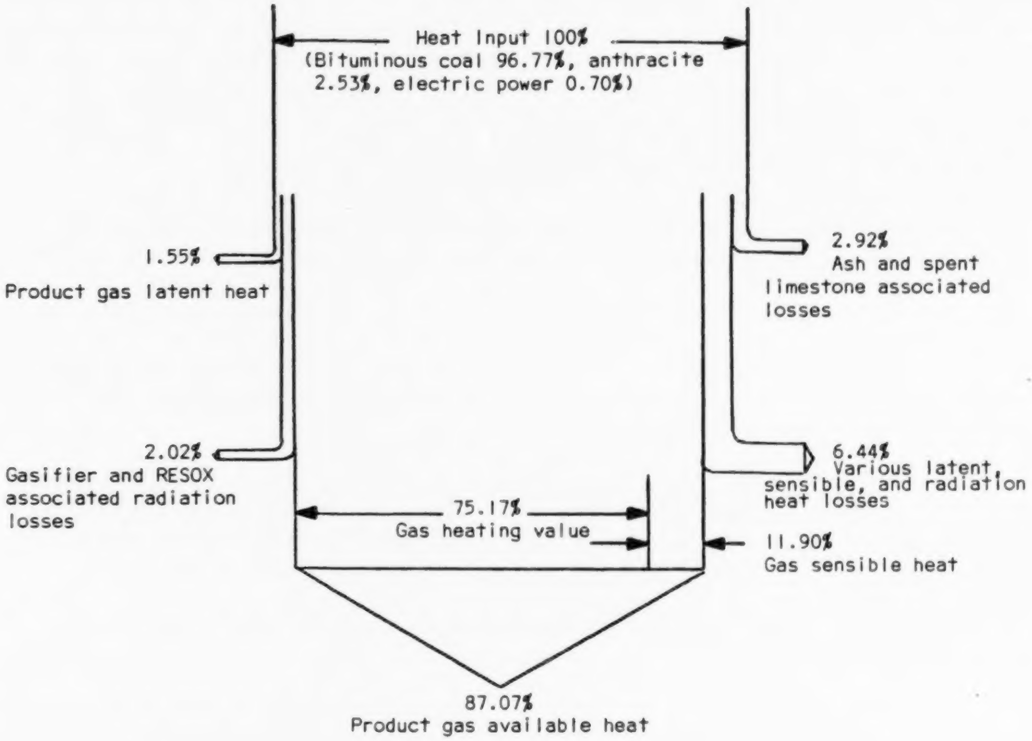
Heat Input 100%
(Bituminous coal 96.77%, anthracite 2.53%, electric power 0.70%)
1.55%
Product gas latent heat
2.02%
Gasifier and RESOX associated radiation losses
2.92%
Ash and spent limestone associated losses
6.44%
Various latent, sensible, and radiation heat losses
75.17%
Gas heating value
11.90%
Gas sensible heat
87.07%
Product gas available heat

Figure 23

Estimated Heat Flow Diagram for Coal Fed CAFB Plant

6.3 Applications

Current

Currently, there is not a single commercial CAFB anywhere in the world. All current and past activities are in the research, development and demonstration categories. The CAFB has operated successfully on oil. In the Fall of 1980, the CAFB system will be operated for 2 to 3 months on coal. This demonstration effort will cover Texas lignite to further demonstrate the technology and to provide additional data for environmental assessments.

Projected

Many utilities are required to burn only low sulfur fuel in order to meet Federal and State emissions regulations. This means that large supplies of heavy residual oils remain untapped as sources of fuel for power plants. In the face of the growing shortage of domestic oil supplies, it is important that maximum use be made of all grades of petroleum. By efficiently converting high sulfur residual oil to clean gaseous fuel, the CAFB process potentially offers an environmentally sound means of freeing this resource for the production of energy (4).

The process has particular importance as a retrofit mechanism for the numerous gas-fired power plant boilers in the southwest. The majority of these boilers cannot be converted to the use of oil or coal. Natural gas for these boilers is expected to be in short supply in a few years. These boilers are in power plants that currently produce approximately 120,000 megawatts of power. Use of the CAFB process could permit this level of energy production to be maintained throughout the useful life of these boilers (4).

In addition, the CAFB process offers a technological advantage over other methods of contaminant removal by avoiding the necessity of cooling and scrubbing the gas. These methods lower the heating value of the product gas and the efficiency of the gasification process (4).

However, it should be noted that potential use of CAFB technology would depend on:

1) The need to find an alternate for natural gas firing for boilers that cannot be converted to an alternate fuel (e.g., fuel oil),
2) The ability to handle in an environmentally acceptable fashion the solid waste and possible trace element air effluents, and
3) The applicability of the CAFB as compared to other fuel supplying alternatives.

6.4 Environmental Considerations

Data applicable for environmental assessments of the overall gasification process is very limited. Any environmental assessment must accordingly be recognized as estimates until data from commercial scale system(s) becomes available.

It should be emphasized that a CAFB is not for consuming fuel but for converting fuel from one form to another. Therefore, the overall effluents should be small as compared to a fuel consuming unit (e.g., coal-fired boiler) of the same fuel input level.

The following was obtained from reference 2 and is based on the EPA supported Esso pilot unit and an assessment of a proposed 250 MW demonstration facility.

Air Emissions

Fugitive air emissions were identified as resulting from the storage and handling of oil, limestone and coal, the latter material being used in the FW's RESOX process to reduce sulfur dioxide emanating from the regenerator to elemental sulfur, and from cooling tower discharges. One of the two fuels used at the pilot plant, bitumen, was found possibly to contain polycyclic organic matter (POM); thus emissions from storage of this material, as well as from other oil feeds, must be investigated further. Cooling tower drift losses would also occur.

Sampling and analysis programs were carried out at the pilot plant operation to quantify stack emissions. Samples were collected during seven separate runs: four fuel oil gasification runs, two bitumen gasification runs and one combustion/startup bitumen run. The field measurement program entailed on-site quantification of SO_2, SO_3, NO_x, H_2S, total particulate and particulate size distributions. In addition, vapor and particulate samples were collected for subsequent chemical analyses. Sulfur dioxide emission rates for fuel oil gasification averaged 0.63 lb/10^6 Btu. Bitumen gasification under conditions of saturated gasifier bed stone (caused by clogging in the gasifier-regenerator stone transfer duct) resulted in an SO_2 emission rate of 1.6 lb/10^6 Btu. Sulfur trioxide emission rates averaged 0.023 lb/10^6 Btu for these same three runs. Total nitrogen oxide emissions ranged from 0.067 to 0.085 lb/10^6 Btu. No significant H_2S was detected in any run. Total particulate emissions ranged from 0.063 to 0.10 lb/10^6 Btu for normal gasification. During fresh stone feed, this rate increased to 0.19 lb/10^6 Btu due to attrition of fresh particles. Particulate size distribution measurements made under gasification conditions for both fuel oil and bitumen feeds indicated roughly one-third of the escaping stack particulate is in the respirable size range.

Laboratory analysis of stack particulate employing spark source mass spectrometry (SSMS), atomic absorption spectroscopy (AA) and electron spectroscopy for chemical analysis (ESCA) demonstrated that vanadium, which is bound in a mixture of oxides, is emitted at a rate of almost 90 percent of the EPA established critical value. No other trace element emissions were found to be of concern. Both particulate and gaseous stack samples were also analyzed for organic functional groups by the procedure outlined by the EPA Level 1 protocol. Flue gas analysis results indicated that emissions of hydrocarbons, quinone and carbonyl compounds are potentially of concern.

Liquid Effluents

Identified liquid effluents are similar to those found in conventional combustion systems. Potential discharges to ambient water could come from coal pile runoff, cooling tower blowdown and boiler blowdown.

Solid Waste

The principal identified solid waste environmental concern would be associated with the disposal of spent, sulfided limestone. Spent stone from a CAFB cannot be disposed of as a solid landfill in an environmentally acceptable manner without treatment. The stone of from 3 to 5 percent CaS would react with moisture in the air to liberate H_2S. The H_2S would be oxidized in the atmosphere to SO_2. This SO_2 would be in addition to the SO_2 emissions from a CAFB unit. It has been estimated that for a typical feedstock that if 90 percent of the fuel sulfur is retained in the CAFB bed and 70 percent of the waste sulfide is converted to sulfate, then the total emissions from the CAFB and the spent stone disposal pile would exceed the current Federal SO_2 emission standard. Clearly, the waste stone would have to be treated to remove the sulfide or render it inert.

6.5 Performance

Current

Currently, there is not a single operational CAFB anywhere in the world. Even so, based on data obtained from the Esso pilot plant, assessments of anticipated performance have been addressed.

The Esso pilot plant had trials with petroleum, pitch, coal, and lignite feedstock. Test results indicated that these feedstocks were usable for the CAFB process. As previously indicated, the pilot plant provided significant reductions in SO_x, NO_x as well as reductions in the emission of vanadium and other metals (5).

There is very limited information on the expected overall energy efficiency of a CAFB facility. Reference 3 indicates that readily identified energy losses associated with the overall system add to an expected loss value of 13 percent of the feedstock input energy. This loss value does not include the sensible heat component of the product gas. It is assumed that the sensible heat would be utilized (see Figure 23).

Projected

According to reference 6, the fuel conversion efficiency limit for the fluid bed portion of a CAFB system is 89 percent. This same reference projects an 81 percent efficiency value by 1990 (i.e., for the fluid bed portion of the overall CAFB system). In contrast, as previously indicated, reference 3 indicates a projected overall system efficiency value of 87 percent. In essence, there is some uncertainty as to the obtainable efficiency of a commercial scale CAFB system.

6.6 Economics

Current

We do not have an operating history to go on. All current activities must be classified as R&D.

Projected

As with any developing or new technology, the cost to process a MBtu is, at best, an estimate. EPA estimates a retrofit CAFB plant to fuel a 500 MWe plant at $172 per kW installed capacity (in 1977 dollars). The operating cost was estimated at 2 - 3 mills per kwh of gaseous energy feed (5).

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7. Indirect Coal Liquefaction

7.1 Overview

Coal liquefaction is an emerging coal conversion alternative that holds promise for near-term commercialization allowing greater utilization of the nation's coal reserves. The liquid products vary with the type of process and the rank of the coal that is utilized.

Coal liquefaction processes can be classified into four types - direct hydrogenation, solvent extraction, pyrolysis, and indirect liquefaction. In direct hydrogenation, hydrogren is added catalytically to coal in a reactor under high pressure and temperature resulting in vapor and liquid phases which are cooled to separate the products, refined to remove by-products and, depending on the fuel product desired, further processed. In solvent extraction, a solvent is used as a hydrogen carrying agent to promote liquefaction under high temperature and pressure to produce the liquid fuels, after purification. In pyrolysis, crushed coal, thermally decomposed in the absence of oxygen, yields solids (char), liquids, and gases. In indirect liquefaction, the coal is first gasified to make a synthesis gas and then passed over a catalyst to produce alcohols (methanol) or paraffinic hydrocarbons.

Research and development of coal liquefaction processes has been underway for many years. The first practical uses of coal-derived liquid fuels were about 1790 when they were used for experimental lighting, heating, and cooking. During World War II, Germany produced liquid fuels from coal in industrial amounts via both direct and indirect liquefaction. Since then, coal liquefaction plants have been constructed in a number of countries but only one plant in Sasol, South Africa, is still producing liquids from coal (via indirect liquefaction). A second plant, SASOL II, has recently begun operation. Commercial demonstration of coal liquefaction has never been accomplished in the United States; current U. S. activities has been limited to research and development and pilot plant programs.

A particular advantage of indirect liquefaction is that essentially all of the sulfur and nitrogen present in the coal can be separated in the gaseous phase and thus eliminated from the liquid products. These materials are difficult and expensive to remove to a very low concentration with direct processes.

The two indirect liquefaction processes receiving significant attention are the Fischer-Tropsch and the Mobil M (methanol). A modification of the Fischer-Tropsch process is in commercial use in South Africa. A range of hydrocarbon products are obtainable with this process. The Mobil process is in the development stage. The principal product of this process is gasoline.

Environmental problems common to fossil energy facilities will also apply to coal liquefaction facilities. Liquefaction facilities do present some unique problems due to incomplete combustion resulting in a wide variety of organic compounds, reducing conditions resulting in H_2S and other reduced sulfur compounds and catalytic processes producing spent catalyst with associated environmental concerns. These problems are generally common to all liquefaction processes. Since no large scale plants are in operation in the U.S., the only available data on emissions and effluents are estimated from pilot plant operations and cannot be quantified for a commercial operation.

Projected thermal efficiencies for indirect coal plants (i.e., Fischer-Tropsch and Mobil) producing pipeline quality synthetic natural gas (SNG) and gasoline and/or diesel fuel are in the 50-60 percent range; the Mobil process being the more efficient. Liquid fuels from indirect liquefaction plants are projected as being more costly than from direct processes. The estimated cost, depending on process in terms of 1980 dollars, is estimated to vary between $7 - 10 per million Btu. This is based on plant coal cost at $1 per million Btu.

Although there remain unanswered questions relating to coal liquefaction (e.g., commercial demonstration, environmental impacts, costs), the successful development of a technology would provide a valuable energy alternative and allow greater utilization of our nation's coal reserves. Additionally, liquid fuels are generally easier to store, transport, and utilize than solid fuels, and during liquefaction, impurities (e.g., sulfur) can be removed making it possible to produce an environmentally acceptable liquid fuel from various ranks of coal.

7.2 Process Description

Concept

The basic objective of coal liquefaction is to convert coal to liquid fuels with minimal production of gases, liquids, and organic solid residues. All ranks of coal can be liquefied although some are more attractive than others. The liquid products vary both with the type of coal used and the particular process applied.

There are several methods for producing a liquid fuel from coal. As with gasification, either hydrogen has to be added or carbon removed from the compounds in the coal. In bituminous coal, for example, the carbon-to-hydrogen ratio by weight is about 16 to 1; in fuel oil the ratio is about 6 to 1. Although liquefaction is a complex process, it can be viewed as a change in the carbon-to-hydrogen ratio that can be accomplished by one of several processes (e.g., indirect liquefaction). The chemical structure of the coal influences the type of chemical reactions that will take place during liquefaction. This structure varies with rank of coal (1).

Detail

Coal liquefaction processes can be grouped into four distinct categories (2, 3, 4):

- Direct hydrogenation (e.g., H-Coal)
- Solvent extraction (e.g., Solvent Refined Coal)
- Pyrolysis (e.g., Clean Coke)
- Indirect liquefaction (e.g., Fischer-Tropsch)

In direct hydrogenation, hydrogen is added catalytically to coal in a reactor under high pressure and temperature resulting in vapor and liquid phases which are cooled to separate the products, refined to remove by-products and, depending on the fuel product desired, further processed. The process conditions (temperature, pressure, and amount of hydrogen added) determine the fuel produced. Processes and products in this category include:

- H-Coal produces boiler fuel or synthetic crude
- Synthoil produces synthetic crude or fuel oil

The solvent extraction process liquefies coal through indirect transfer of hydrogen to the coal using a process-derived solvent and a hydrogen atmosphere. Processes and products in this category include:

- Solvent Refined Coal produces boiler fuel or low-sulfur solid fuel
- CO-Steam produces fuel oil
- Donor Solvent produces liquid and gas products

In pyrolysis, crushed coal, thermally decomposed in the absence of oxygen, yields solids (char), liquids, and gases. These products, via the same action, have been produced from coal for well over 100 years as the by-product of coking operations. Processes and products in this category include:

- Hydrocarbonization produces fuel oil
- Clean Coke produces coke and liquid fuels
- Flash Pyrolysis produces fuel oil, coke, gas

Indirect liquefaction involves the initial gasification (see Section 5, Low/Medium-Btu Gasification) of coal to produce a mixture of CO and H_2 (synthesis gas), which is purified and converted to liquid fuels by reaction over appropriate catalysts to produce alcohols (methanol) or paraffinic hydrocarbons (3, 4). A particular advantage of indirect liquefaction is that essentially all of the sulfur and nitrogen present in the coal can be separated in the gaseous phase and thus eliminated from the liquid products (5). These materials are often difficult and expensive to remove to a very low concentration with direct processes (5). A major environmental difference between direct and indirect liquefaction is that direct processes produce a significant amount of potentially carcinogenic aromatic organic compounds. The indirect category processes and products include:

- Mobil Process produces gasoline

- Fischer-Tropsch produces liquid fuels and chemical products.

The Fisher-Tropsch process is significant in that it is the only large commercial coal liquefaction plant in operation. (It is located in Sasol, South Africa.) Discussions on the above two indirect liquefaction processes follow:

Mobil Methanol Technology (1, 6, 7)

The Mobil Oil Corporation is developing an improved process for production of motor fuels by indirect liquefaction. The product gasoline has a high octane rating and is free of heavy ends so that product upgrading is not necessary.

The Mobil process involves the conversion of methanol to gasoline. When starting with coal, coal is first converted to a synthetic gas with subsequent conversion to methanol by proven commercial technology. The methanol is then converted to gasoline by means of the Mobil process. Figure 24 indicates the basic concept.

The Mobil process is claimed to be about 92 percent energy efficient. The process does not appear to have any material-of-construction problems and is said to be essentially free of undesirable by-products. Solid-liquid separation problems are avoided as the coal feed is gasified. The amount of durene, a gum forming material, formed by this process conceivably could be a disadvantage. In high concentration above 5 to 6 percent, it can cause drivability problems. It has a high octance and is a desirable constituent if the concentration can be kept down. Mobil claims knowledge to date indicates they can control the durene content to less than 4 percent, a value within desired limits.

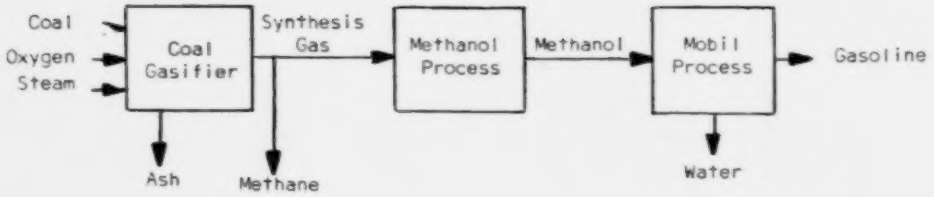

Figure 24

Synthesized Gasoline From Coal

In the overall Mobil indirect liquefaction process (Figure 25), synthetic gas is produced from coal via any of the existing medium-Btu coal gasification processes (e.g., Lurgi, Koppers-Totzek, Texaco). When the synthesis gas is shift converted to the proper carbon-to-hydrogen ratio, methanol becomes an alternative product from any process than can produce high-Btu gas. In practice, the synthesis gas is converted to methanol by any of a number of proven processes (e.g., the low pressure ICI methanol process). The yield of methanol is maximized by a combination of optimum reactor conditions and catalyst and the recycle of unreacted gases. High catalyst selectivity limits the production of ethers, ketones, and higher alcohols. Carbon dioxide is removed prior to converting the synthesis gas to methanol thereby qualifying the product as a feed for the Mobil process.

The Mobil process converts methanol into a high-octane gasoline by dehydration over a shape selective zeolite catalyst. The secret of the process is really the catalyst, a unique zeolite identified a few years ago. Mobil's initial developmental efforts are directed at the fixed-bed reactor configuration. Even so, considerations are also being given to tubular and fluid-bed catalytic reactor units.

In the process, methanol is blended with water and charged as a vapor into the reactor. The product is separated from the catalyst, filtered and condensed and the water is separated from the hydrocarbon components. The principal output components are premium gasoline (approximately 90% of Btu output) and LPG (approximately 10% of Btu output).

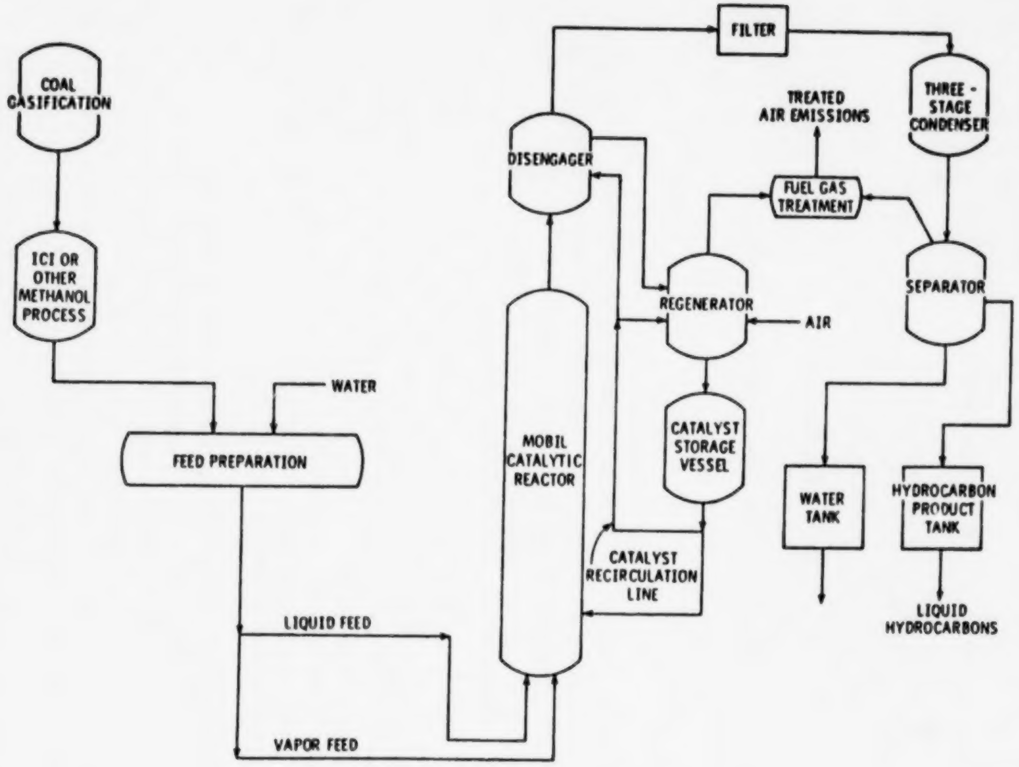
COAL GASIFICATION
ICI OR OTHER METHANOL PROCESS
WATER
FEED PREPARATION
LIQUID FEED
VAPOR FEED
MOBIL CATALYTIC REACTOR
DISENGAGER
FILTER
CATALYST RECIRCULATION LINE
REGENERATOR
AIR
CATALYST STORAGE VESSEL
FUEL GAS TREATMENT
TREATED AIR EMISSIONS
THREE - STAGE CONDENSER
SEPARATOR
WATER TANK
HYDROCARBON PRODUCT TANK
LIQUID HYDROCARBONS

Figure 25

Mobil Catalytic Process

Fischer-Tropsch Technology (5, 6, 7)

The Fischer-Tropsch (F-T) indirect liquefaction process is based on the F-T catalytic reactions that were discovered in 1923. The F-T reactions can cover a range of combinations using different metallic oxide catalysts to react hydrogen and carbon monoxide to form a mixture of olefins, paraffins, and alcohols. These reactions are exothermic and are not specific to the formation of any single compound. The range of products from the F-T process depends on the reaction and temperature conditions as well as the type of catalyst used and the composition of (input) reactants.

In the complete scheme of the F-T process, the coal is initially gasified (e.g., using a Lurgi gasifier), then cleaned of hydrogen sulfide, carbon monoxide and impurities, and finally shift converted before it enters a catalytic reactor.

The major reason for interest in the F-T process is that a commercial plant using a modification of this method is currently operating in South Africa (SASOL I). In the commercialized process, two reactors using different catalysts and temperatures and pressures, process gases with different carbon and hydrogen ratios into different products. Its main drawbacks are that a great deal of reaction heat is produced (i.e., efficiency suffers) and the process is apparently expensive. As previously indicated, the process can produce a wide variety of hydrocarbons ranging from methane to light oils. The different products are produced with varying degrees of overall thermal efficiency.

The gasification can be accomplished with any of a number of different gasifiers. SASOL I, as shown in Figure 26, employs 13 Lurgi high-pressure, steam-oxygen coal gasifiers to produce a product gas containing carbon monoxide, tars, and oils as the main components. The crude product gas is cleaned of carbon monoxide, hydrogen sulfide, organic sulfur, ammonia, and phenol. The cleaned gas is partitioned into two streams. One stream is adjusted to a hydrogen-to-carbon monoxide ratio of two to one and fed to a fixed-bed catalytic reactor (ARGE) that is operating at 450°F and 360 psi. The products from this reactor are mainly straight chain and medium boiling oils, diesel oil, LPG, and some alcohols.

The remaining stream of purified gas (i.e., gas from the Lurgi gasifiers) is combined with reformed product gas (to increase the hydrogen-to-carbon monoxide ratio) and sent to a fluidized-bed reactor (i.e., Synthol: the U.S. developed Kellogg synthesis). The operating conditions are 620°F and 330 psi. The products from this reactor are mainly gasoline, fuel oil fractions, and various chemical products. The gasoline has a lower octane rating than the natural petroleum-based gasoline that is currently marketed in the United States.

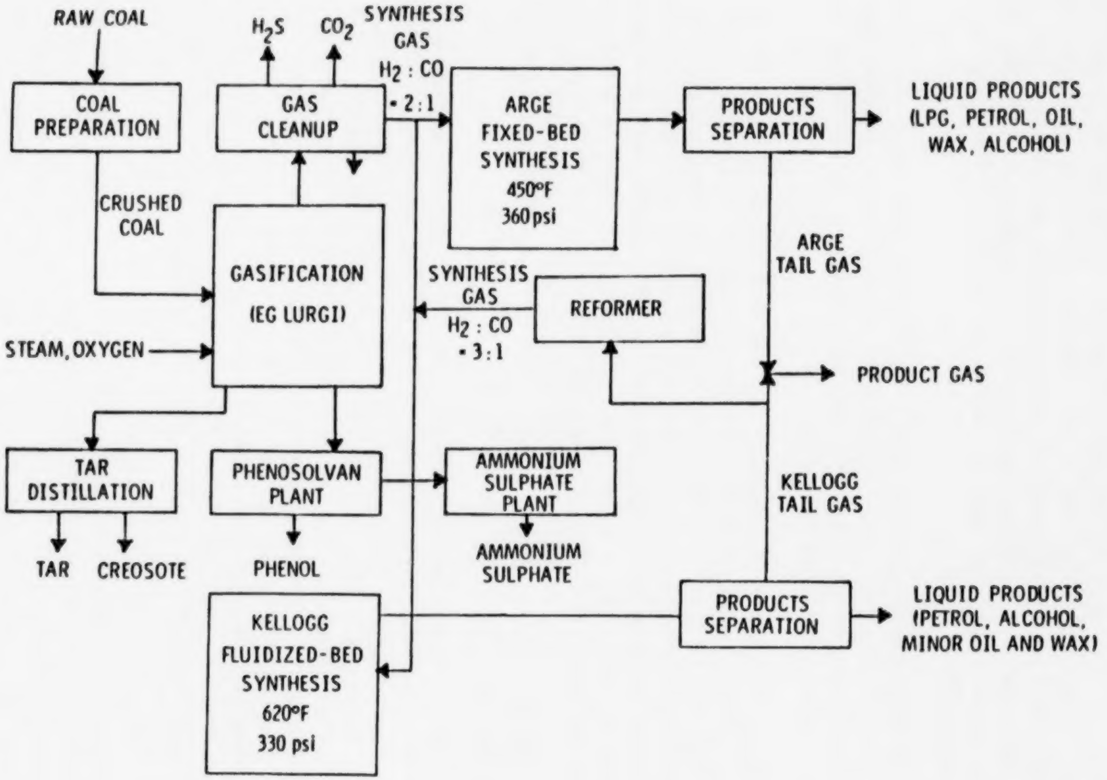
RAW COAL
COAL PREPARATION
CRUSHED COAL
STEAM, OXYGEN
GASIFICATION (EG LURGI)
GAS CLEANUP
H_2S
CO_2
SYNTHESIS GAS $H_2 : CO$ • 2:1
ARGE FIXED-BED SYNTHESIS 450°F 360psi
PRODUCTS SEPARATION
LIQUID PRODUCTS (LPG, PETROL, OIL, WAX, ALCOHOL)
ARGE TAIL GAS
PRODUCT GAS
REFORMER
SYNTHESIS GAS $H_2 : CO$ • 3:1
KELLOGG TAIL GAS
TAR DISTILLATION
TAR
CREOSOTE
PHENOSOLVAN PLANT
PHENOL
AMMONIUM SULPHATE PLANT
AMMONIUM SULPHATE
KELLOGG FLUIDIZED-BED SYNTHESIS 620°F 330 psi
PRODUCTS SEPARATION
LIQUID PRODUCTS (PETROL, ALCOHOL, MINOR OIL AND WAX)

Figure 26

Fischer-Tropsch Synthesis

Overviews on SASOL I and SASOL II, based on reference 8, follow:

SASOL I

LOCATION:	Sasolburg, South Africa
DESCRIPTION:	Gasification in Lurgi gasifiers Two Fischer-Tropsch synthesis units; 1) ARGE fixed-bed unit, temp. 230°C; press. 23 atm.; catalyst, pelleted precipitated iron. 2) Kellogg SYNTHOL process, high-velocity entrained-flow reaction using a doubly promoted iron catalyst.
SIZE:	10,000 bpd
STATUS:	In commercial production since 1956
YEARS OPERATION:	24
COAL TYPE:	Subbituminous
MAJOR PRODUCTS:	Liquid fuels, chemicals, and fuel gas.

SASOL II

LOCATION:	Secunda, South Africa
DESCRIPTION:	Gasification in Lurgi gasifiers, Fischer-Tropsch synthesis unit using the Kellogg SYNTHOL process
SIZE:	Nominal 40,000 bpd
STATUS:	Anticipate ready for commissioning in 1980
COAL TYPE:	Subbituminous
MAJOR PRODUCTS:	Liquid fuels (gasoline is the major product).

Process variabilities for indirect liquefaction processes are such that any efficiency value must be used with caution. Due to the proprietary nature of indirect liquefaction technology (e.g., SASOL), a detailed heat balance was not obtainable. Even so, a specific comparison between the Fischer-Tropsch (F-T) and the Mobil processes was obtained. Reference 9 provides a performance comparison between the Mobil methanol-to-gasoline technology and the commercially available F-T technology for the production of the motor gasoline meeting U.S. quality standards. This reference covers complete conceptual plant complexes using the Lurgi dry-ash, pressure technology to gasify subbituminous coal. Except for the Mobil process, processes used are commercially available. Co-production of products, namely SNG, LPG, and gasoline is practiced. Efficiency values contained in reference 9 are not based on detailed mass balances and associated heat balances, but on the known performance of specific processes. A thermal efficiency comparison (reference 9) between the commercial F-T technology and the Mobil methanol-to-gasoline technology for the production of motor gasoline (with other output products) from U.S. subbituminous coal is provided by Table 17. A typical heat balance for the gasification portion of indirect liquefaction appears in Section 5.

Table 17

Thermal Efficiencies

	Methanol-to-Gasoline		Fischer-Tropsch	
	Btu/hour (10^6 Btu)	Percent of Input	Btu/hour (10^6 Btu)	Percent of Input
Input				
Coal	19,383		19,708	
Coal Fines (excess)	(872)		--	
Methanol	--		3	
Total Input	18,511		19,711	
Output				
SNG	6,067	32.8	7,243	36.8
C_3 LPG	247	1.3	176	0.9
C_4 LPG	385	2.1	26	0.1
10 RVP Gasoline	4,689	25.3	2,842	14.4
Diesel Fuel			514	2.6
Heavy Fuel Oil			147	0.7
Subtotal	11,388	61.5	10,948	55.5
Alcohols			290	1.5
Sulfur	19	0.1	19	0.1
Ammonia	83	0.5	83	0.4
Power*	18	0.1	11	0.1
Total Output	11,508	62.2	11,351	57.6

* Direct thermal equivalent value (thermal efficiencies are highly dependent on product mix, see Section 7.5)

7.3 Applications

Current

The conversion of coal to liquids has never been accomplished commercially in the United States. In the past, coal to oil plants were constructed in a number of countries. Currently there is only one plant, in South Africa, producing liquids from coal. This plant, SASOL I, employs an indirect liquefaction process.

Projected

The successful development and commercial demonstration of a coal liquefaction technology would provide a valuable energy alternative and would allow greater utilization of the nation's coal resources. There are many advantages to liquefying coal. Liquid fuels are generally more attractive than solid fuels in that they are easier to store, transport, and utilize. Also, during liquefaction, impurities found in coal (e.g., sulfur, metals, and ash) can be removed or their concentrations greatly reduced. Thus, it is possible to produce clean, environmentally acceptable liquid fuels from various ranks of coal. The development and future commercial use of a coal liquefaction technology are dependent on many factors. Some of the more important include:

- The demonstration (large scale) of a viable technology,
- The ability to satisfy environmental concerns, and
- The ability to produce a commercially usable liquid fuel with an acceptable overall efficiency rating and cost.

7.4 Environmental Considerations

Although many of the environmental issues associated with conventional fossil fuel utilization are common to coal conversion processes, liquefaction technology presents some unique problems (2). These include: the identification of materials with carcinogenic, mutagenic, and related effects; characterization and treatment of wastes and fugitive emissions and effluents; and disposal of sludges and solid wastes. These problems are generally common to all liquefaction technologies; however, particular processes may have to be evaluated individually. Liquefaction does have the inherent advantage of separating the processing of the coal from the ultimate utilization. Since impurities can be removed from the coal during liquefaction, a "clean" fuel can be delivered to the utilization site (possibly an urban area) and thus the fuel using facility will not have to cope with the impurities.

Identified Pollutants

Air Emissions

Development and commercialization of a coal liquefaction industry creates a concern with regard to the introduction of air pollutants into the atmospheric environment (2). The typical materials produced in a coal liquefaction facility which could have a detrimental impact on air quality include: hydrogen sulfide, ammonia, particulate matter (e.g., coal dust and process fines), hydrocarbons, sulfur dioxide, hydrogen cyanide, small amounts of nitrogen dioxide, polycyclic hydrocarbons, and heavy metals. These emissions result from such activities as coal handling and preparation, fuel combustion, coal gasification, raw gas and liquid product cleanup, sulfur recovery, catalyst regeneration, and product upgrading and storage.

The major air emissions from liquefaction facilities are generally known and conventional control techniques possibly could be effectively applied. The Dravo Corporation, in a 1976 handbook produced for the U.S. Government, provides information on a number of industrial sulfur removal systems. (Handbook of Gasifiers and Gas Treatment Systems, FE-1772-11, February 1976.) The majority of the proprietary systems described are for removing H_2S from industrial gases. Some systems in addition to removing H_2S also remove other gaseous effluents (e.g., CO_2, NH_2, HCN). Almost all of the addressed systems have been in existence for many years with significant industrial usage. Such systems include the Rectisol and the Stretford processes that have been used for selectively cleaning up gaseous impurities from processes used to convert oil or coal to other fuel form(s). Liquefaction air emission streams may contain impurities which could reduce the capabilities of commercially available control technologies.

However, in some instances, advanced controls may have to be developed before coal conversion plants are constructed on a commercial scale. In addition, airborne pollutants will be transported into the general environment and possibly transformed into other compounds after emission from coal liquefaction facilities.

The 1977 Clean Air Act amendments mandate that fossil energy facilities, including coal conversion plants, utilize the best available technology to control pollutants. Coal liquefaction (and other process facilities) constructed in non-attainment areas will be subject to emission trade-off policies. The energy and cost penalties of applicable air pollution controls must be characterized as well as the secondary pollutants which may be emitted by the controls.

Liquid Effluents

Coal liquefaction processes may produce waste effluents which have broad temperature and pH ranges and may contain a variety of materials such as: suspended particles, ammonia, toxic trace metals, phenols, aromatic hydrocarbons, thiophenes, aromatic amines, and other organic compounds (2). Conventional control and wastewater treatment techniques can be applied to most of these materials. However, particularly troublesome areas requiring more study include: phenols, trace metals and the final disposal of the effluents (2).

Water quality may also be affected by gaseous streams, fugitive effluents and air emissions which may settle or be washed into water bodies by rain. Improper handling or disposal of solid wastes may also release dissolved and suspended solids and organics. Control and treatment options compatible with water discharge standards should be identified and their effects evaluated.

Effluent constituents may accumulate and/or be transformed in the water column and biotic sediment or aquatic ecosystems. Current methods for predicting the movement of waste contaminants through surface and groundwater systems must be evaluated for locations where liquefaction facilities may be located.

Solid Waste

Solid wastes generated by coal liquefaction processes consist primarily of (gasifier) ash and refuse removed from the coal and sludges and solids recovered from waste treatment processes. The major solid waste streams, as well as minor ones such as spent catalyst, must be characterized and appropriate disposal techniques determined. Where appropriate, new treatment and disposal techniques may need to be developed.

Conventional disposal of solid wastes (especially ash) in offsite landfills will require transport and handling equipment and relatively large areas of land. The handling, transportation and disposal of wastes must be controlled to prevent fugitive dust emissions and accidental discharges. Groundwater leaching is another concern which must be evaluated if landfills are used as disposal areas for coal liquefaction wastes. Physical and chemical reactions involved, effects of various methods of disposal upon leachability, effective control and containment techniques, and compliance with new State hazardous waste disposal regulations must all be evaluated.

A DOE publication has estimated that the total solid wastes to be disposed of by a large-scale Fischer-Tropsch facility would be about 1000 to 4500 tons per day (2). Most of these wastes will be in the form of ash. Disposal of these solid wastes (from a Fischer-Tropsch plant) would cover approximately 250 to 1125 acres to a depth of 10 feet over a 20-year period.

Regulatory Impacts

Each liquefaction technology will have to be evaluated separately as to regulatory impacts. Because of the difference in technologies and also varying state and local regulations, siting of a major coal liquefaction facility must be approached on a case-by-case basis.

A coal conversion facility must comply with regulations and standards including requirements of the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Federal Nonnuclear Research and Development Act, and the National Environmental Policy Act as well as applicable State laws. Failure to comply has the potential of halting all progress toward commercialization.

Current standards for hazardous air pollutants limit mercury, beryllium, and lead emissions. These standards conceivably could put a limit on coal types than can be utilized in future demonstration plants. Since effluent guidelines have not been developed for most fossil energy technologies, permit requirements are determined on a case-by-case basis by States or by EPA (2).

Disposal of specific materials used in coal liquefaction may be regulated in the future. Currently, solid waste disposal must comply with stringent standards. Monitoring is required and State or EPA permits for all landfills will be required by 1 April 1988.

The Resource Conservation and Recovery Act of 1976 (RCRA) has guidelines for the land disposal of solid wastes (40 CFR 241). These standards set minimum levels of performance for any solid waste land disposal site. Additional standards have been proposed for disposal of solid wastes that contain hazardous pollutants. All future coal liquefaction facilities will have to abide by these solid waste standards (10).

Undoubtedly, the coal conversion industry would benefit from the experience of the petroleum industry in dealing with complex organic substances and new processes while complying with governing statutes.

7.5 Performance

Current

Currently, there are no commercial coal liquefaction plants in the United States. Therefore, all projections are based on available data associated with SASOL I and assessments relating to SASOL II and efforts in the U.S. still in the developmental stage.

The overall thermal efficiency of the Fischer-Tropsch is dependent on the output product mix. The projected overall thermal efficiency of a modern Fischer-Tropsch plant that would predominately produce pipeline quality SNG with a lesser amount of liquid fuels (32% on a Btu basis) is estimated by reference 9 to be approximately 55 percent (see Table 17). The same reference projects that the Mobil process producing pipeline quality SNG with almost as much gasoline (i.e., on a Btu basis) would have an overall thermal efficiency of approximately 60 percent. Noteworthy is the fact that a greater percentage of the Mobil process output is in the form of gasoline and that these efficiency values are based on giving credit to all output products. When these processes are optimized for gasoline yield and credit is not given for product gas the efficiency values are significantly less (e.g., 32% for F-T per reference 11).

Projected

The general expectation, based on substantial development efforts and overseas experience, e.g., SASOL I, is that efficiencies of indirect liquefaction processes will not measurably improve (over currently anticipated values) in the forseeable future. System losses are well understood and substantial efforts have already been directed at utilizing all system available energy.

7.6 Economics

Current

Since there are no commercial coal liquefaction processes currently in operation in the United States, the economics must be projected.

Projected

The cost to produce a million Btu of a liquid fuel is, at best, an estimate. There are many factors that could greatly influence the cost of fuel from an indirect liquefaction plant. These include inflation, interest rates, fuel cost, pollution control, process efficiency, and others. It should be noted that the projected cost of liquid fuel from an indirect liquefaction process is consistently higher than for a direct process. Reference 12 projects the costs of liquid fuels from indirect liquefaction processes to be in the range of $7 - 10 per million Btu. This is in terms of 1980 dollars with coal costs at one dollar per million Btu.

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8. High-Btu Gasification

8.1 Overview

High-Btu gasification of coal will provide a means to augment our supply of natural gas. Coal can be gasified by any of several processes: synthesis, pyrolysis, or hydrogasification. In synthesis, coal or char is reacted with steam and oxygen and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In the process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form methane.

To produce a pipeline quality gas (900 to 1,050 Btu/ft^3), medium-Btu gas (e.g., from hydrogasification) is cleaned and further treated. This further treatment could include a shift conversion to obtain proper carbon monoxide to hydrogen ratio followed by a second purification process, followed by a methanation process. The second purification process removes carbon dioxide and hydrogen sulfide. The shift conversions and methanation steps are catalytic process operations.

A number of high-Btu gasification second generation processes have or are being investigated by the U. S. Department of Energy. These include the CO_2 Acceptor, BI-GAS, HYGAS, and the Synthane processes. Each of these processes have unique characteristics and research and development must proceed accordingly. Beside the above, there are a number of other processes some of which have not been fully considered by DOE.

To an extent, environmental concerns common to coal fired boiler facilities will also generally apply to coal gasification facilities. Additional unique adverse environmental impacts are difficult to estimate. No commercial plants are in operation anywhere in the world and assessment must be based on limited information from pilot plants. In addition, information from a pilot plant may not be representative of a commercial operation.

Projected overall energy efficiencies for coal gasification have been estimated to be in the 58 to 68 percent range. A 1977 estimate of the gate cost of high-Btu gas produced by a gasification plant was \$4 to \$6 per million Btu. Current estimates are somewhat higher.

8.2 Process Description

Concept

Figure 27 is a generalized diagram that shows the basic processing steps common to different types of gasification processes. An overview of the overall process consistent with the figure follows.

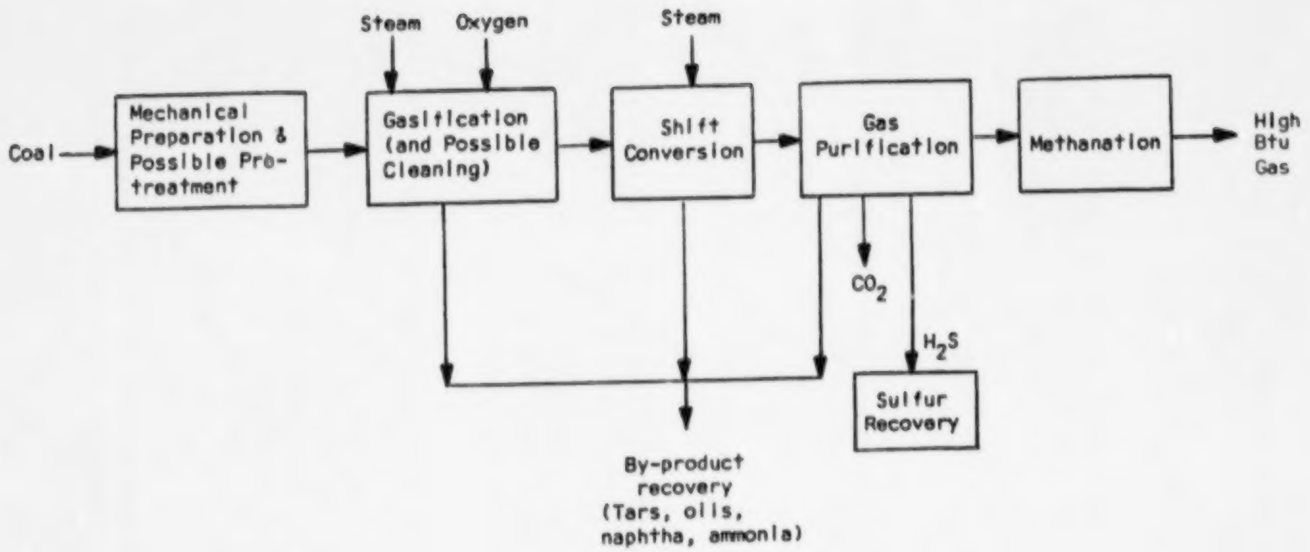

Steam
Oxygen
Steam
Coal
Mechanical Preparation & Possible Pre-treatment
Gasification (and Possible Cleaning)
Shift Conversion
Gas Purification
Methanation
High Btu Gas
CO_2
H_2S
Sulfur Recovery
By-product recovery (Tars, oils, naphtha, ammonia)

Figure 27

Generalized Flow Diagram - High-Btu Gas

The first step, coal preparation with possible pretreatment, can be simple or complex depending on the characteristics of the specific gasification process. This step can range from crushing or grinding to proper size to more sophisticated preparation including sizing, physical beneficiation, and drying. In addition, in certain processes, it may be necessary to pretreat an agglomerating coal feed to destroy the coking properties (1, 2).

The three primary ingredients needed to chemically synthesize gas from coal are carbon, hydrogen, and oxygen. Coal provides the carbon; steam is the most commonly used source of hydrogen, although hydrogen is sometimes introduced directly from an external source; and oxygen is supplied (i.e., for medium-Btu gas) as pure oxygen. Heat can be supplied either directly by combusting coal and oxygen inside the gasifier or from an external source (1).

Coal can be gasified by any of several processes: synthesis, pyrolysis, or hydrogasification. In synthesis, coal or char is reacted with steam and oxygen and produces the heat for a reaction that produces a mixture of hydrogen and carbon monoxide. In pyrolysis, coal is heated in a starved air atmosphere. In the process, some gas and liquids result, the major product being a coke residue. In hydrogasification, coal, coke, or char is reacted with hydrogen to form methane.

Three combustible gases produced by coal gasification processes are carbon monoxide (CO), methane (CH_4) and hydrogen (H_2). Methane, the primary component of natural gas, is similar to natural gas in heating value. Carbon monoxide and hydrogen heating values are approximately equal, being about one-third the methane/natural gas value. Several nonproduct gases are also produced, including carbon dioxide, hydrogen sulfide, and nitrogen (1).

A major goal for most coal gasification processes is to produce a high quality gas during the initial gasification stage. The product from each process is determined primarily by the methods used to introduce hydrogen, oxygen, and heat into the gasifier. To produce a pipeline quality gas, medium-Btu gas (e.g., from hydrogasification) is cleaned and further upgraded. Three steps are involved in upgrading raw gases produced during the gasification stage: shift conversion, purification, and methanation. Shift conversion combines carbon monoxide and water to produce carbon dioxide and hydrogen ($CO + H_2O \longrightarrow CO_2 + H_2 + \text{heat}$). This shift is necessary to adjust the hydrogen and carbon monoxide to the 3:1 ratio required for methanation. A catalyst is used in this reaction. After shift conversion, the gas is purified to less than 1.5 percent carbon dioxide by volume and less than one ppm of hydrogen sulfide. Methanation follows, reacting carbon with hydrogen to produce methane ($CO + 3H_2 \longrightarrow CH_4 + H_2O + \text{heat}$). Catalysts are used for this reaction. The basic upgrading process is fairly standardized, and the major choices involve engineering details rather than alternative processes (1).

It should be noted that gas purification can largely be accomplished using developed processes. The Dravo Corporation, in a 1976 handbook produced for the U. S. Government, provides information on a number of industrial sulfur removal systems. The covered proprietary systems are for removing H_2S from industrial gases. Some systems, in addition to removing H_2S, also remove other gaseous effluents (e.g., CO_2, NH_3, HCN). Almost all of the addressed systems have been in existence for many years with significant industrial usage. Such systems include the Rectisol and the Stretford processes that have been used for selectively cleaning up gaseous impurities from processes used to convert oil to other fuel form(s). There are over 35 Rectisol and 50 Stretford plants currently in operation worldwide.

Detail

A large number of high-Btu gasification processes have been proposed. Major high-Btu processes that have or are currently being investigated by the U. S. Department of Energy include: CO_2 Acceptor, BI-GAS, HYGAS, and Synthane. Detailed overviews of these processes based on a DOE report follow (3).

CO_2 Acceptor

A diagram of the carbon dioxide acceptor process is shown in Figure 28. The pilot plant is located in Rapid City, South Dakota. In this process, raw coal is crushed to 8 x 100 mesh in hot-gas-swept impact mills, where the moisture content is also reduced from approximately 38 weight percent to about 16 weight percent. The hot gas, at approximately $850^{\circ}F$, is supplied by the combustion of coal fines recovered from mill offgas. The temperature of the furnace flue gas injected into the mills is moderated with recycle of mill offgas.

The crushed and partially dried coal is dried to 0-5 weight percent moisture in flash dryers operating at about $240^{\circ}F$. The dried coal is conveyed in fluidized-bed preheaters where the temperature is raised to approximately $500^{\circ}F$. The preheated coal is fed into the gasifier near the bottom of a fluidized bed of char. Rapid devolatilization occurs, followed by gasification of the fixed carbon with steam.

The gasifier temperature ranges between $1480^{\circ}F$ and $1550^{\circ}F$. Heat for the gasification reactions is supplied by a circulating stream of calcium oxide called acceptor. This acceptor which can be either limestone or dolomite, supplies the heat needed for gasification, primarily through the reversible exothermic/endothermic carbon dioxide acceptor reaction:

$$CaO + CO_2 \rightleftarrows CaCO_3 + heat$$

The acceptor, reduced to the desired size distribution (generally 6 x 14 mesh) enters the gasifier above the fluidized char bed, showers

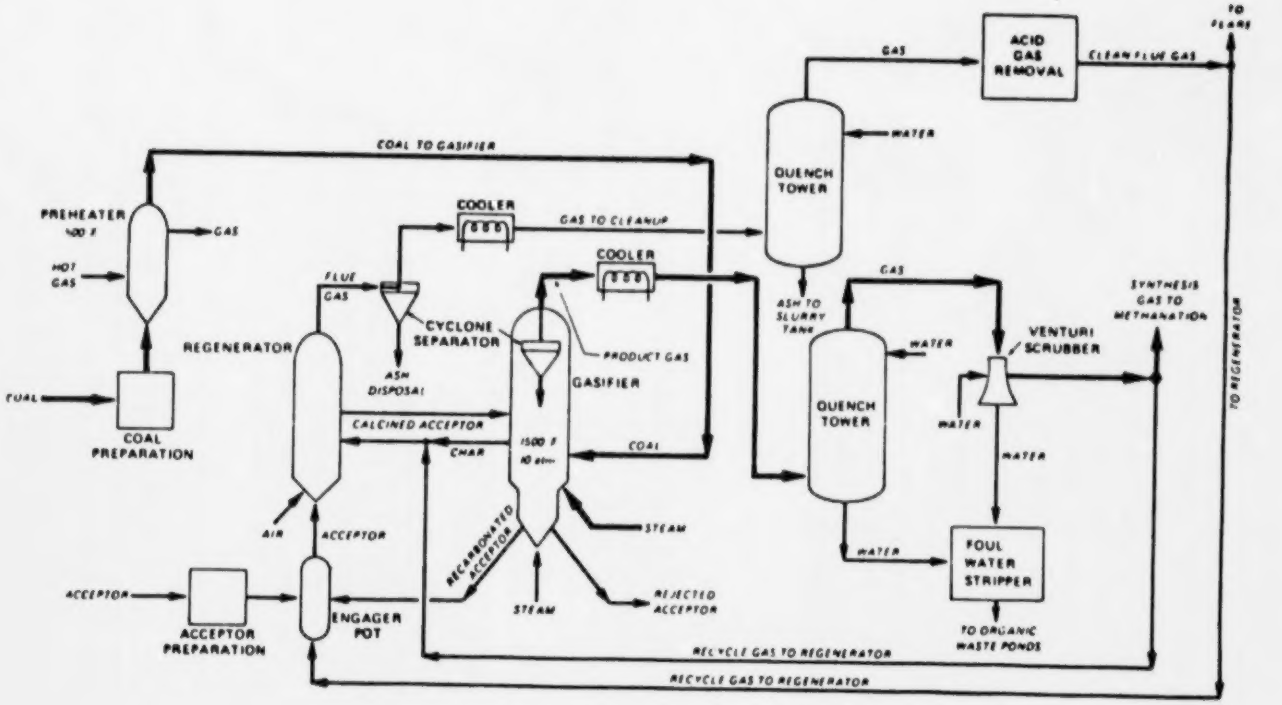

TO FLARE
ACID GAS REMOVAL
GAS
CLEAN FLUE GAS
COAL TO GASIFIER
PREHEATER 400 F
GAS
HOT GAS
FUAL
COAL PREPARATION
COOLER
GAS TO CLEANUP
QUENCH TOWER
WATER
FLUE GAS
CYCLONE SEPARATOR
ASH DISPOSAL
REGENERATOR
COOLER
PRODUCT GAS
GASIFIER
CALCINED ACCEPTOR
CHAR
COAL
1500 F
10 atm
ASH TO SLURRY TANK
GAS
QUENCH TOWER
WATER
VENTURI SCRUBBER
WATER
WATER
SYNTHESIS GAS TO METHANATION
AIR
ACCEPTOR
RECARBONATED ACCEPTOR
STEAM
STEAM
REJECTED ACCEPTOR
WATER
FOUL WATER STRIPPER
TO ORGANIC WASTE PONDS
ACCEPTOR
ACCEPTOR PREPARATION
ENGAGER POT
RECYCLE GAS TO REGENERATOR
RECYCLE GAS TO REGENERATOR
TO REGENERATOR

Figure 28

Carbon Dioxide Acceptor Process Schematic through the bed, and collects in the gasifier boot. Steam needed for hydrogasification enters through the gasifier boot and the distributor ring. Spent dolomite, used during startup to avoid plugging, is replaced by fresh acceptor after circulation rates are established and the system is at process temperature and pressure. Product gas from the gasifier passes through a steam-generating heat exchanger, then goes to the gas cleanup section. The regenerator is used for calcining the acceptor.

Both the flue gas from the regenerator and the product gas are cleaned; the clean flue gas is either returned to the regenerator or flared, and the clean synthesis gas is sent to the methanation unit where the heating value of the gas is raised to pipeline quality, approximately 1000 Btu per standard cubic foot. The methanation facilities include a shift converter, carbon dioxide absorber, hydrodesulfurizer, zinc oxide sulfur guard, and a packed-tube methanator. A Dowtherm system is used to remove the heat generated by the strongly exothermic methanation reaction.

BI-GAS

The BI-GAS process is a two-stage, high-pressure, oxygen-blown system using pulverized coal and steam in an entrained flow. The pilot plant is located in Homer City, Pennsylvania. A diagram of the BI-GAS process is provided in Figure 29.

Raw coal is first pulverized so that approximately 70 percent will pass through 200-mesh. The coal, mixed with water, is fed to a cyclone where the solids are concentrated into a slurry. Coarse underflow from the cyclone is sent to a wet grinding mill for further crushing. The slurry is further concentrated in a thickener and centrifuge, repulped and mixed with flux to generate the desired concentration, and fed to the downstream high pressure feed system.

A high pressure slurry pump picks up the blended slurry and transports it under pressure to a steam preheater. The hot slurry is then contacted with hot recycle gas in a spray dryer for nearly instantaneous vaporization of the surface moisture. The coal is conveyed to a cyclone at the top of the gasifier vessel by the stream of water vapor and inert recycle gas, as well as additional recycled gas from the methanator. The coal is separated from the hot recycle gas in the cyclone and flows by gravity to the gasifier.

The coal enters the gasifier through injector nozzles near the throat separating the stages. Steam is introduced through a separate annulus in the injector. The two streams combine at the tip and join the hot synthesis gas rising from Stage 1. A mixing temperature of about 2200°F is attained rapidly and the coal is converted to methane, synthesis gas, and char. The raw gas and char rise through Stage 2, leave the gasifier at

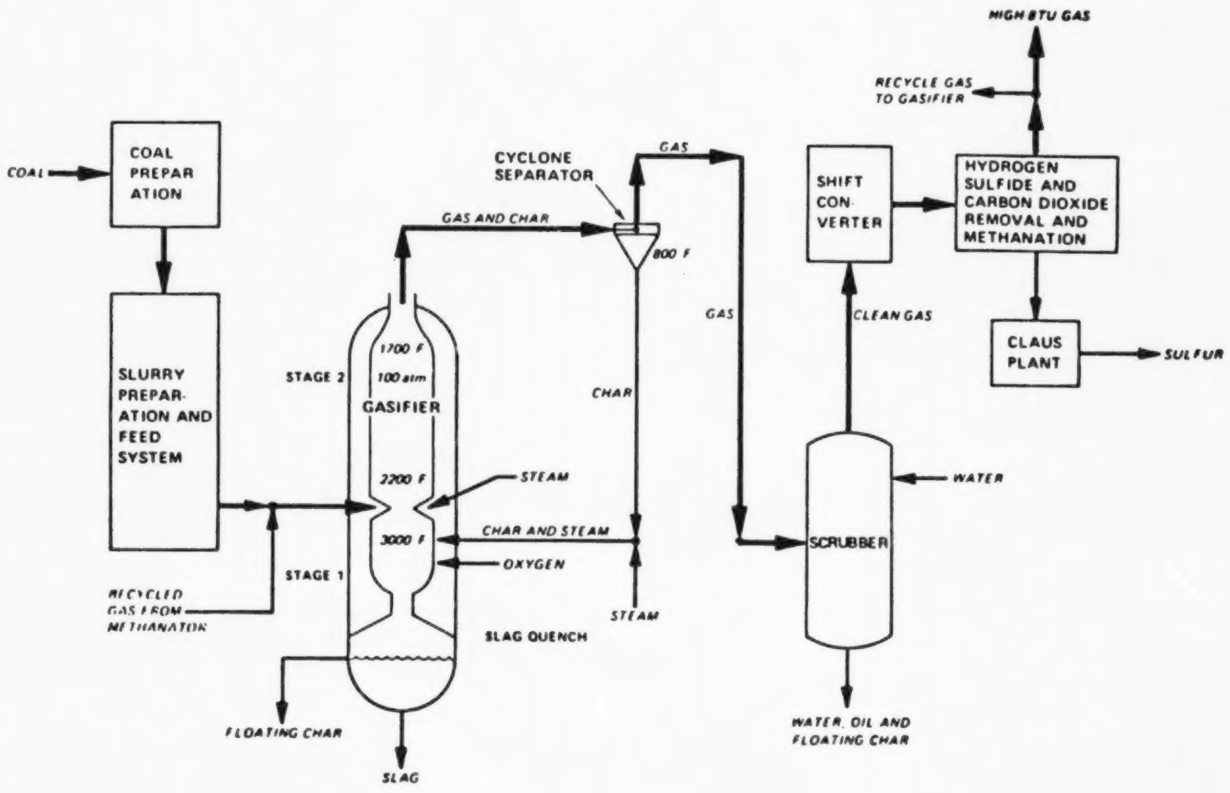

COAL
COAL PREPAR ATION
SLURRY PREPAR- ATION AND FEED SYSTEM
RECYCLED GAS FROM METHANATOR
STAGE 2
STAGE 1
1700 F
100 atm
GASIFIER
2200 F
3000 F
STEAM
CHAR AND STEAM
OXYGEN
SLAG QUENCH
FLOATING CHAR
SLAG
GAS AND CHAR
CYCLONE SEPARATOR
800 F
CHAR
STEAM
GAS
GAS
SCRUBBER
WATER
WATER, OIL AND FLOATING CHAR
CLEAN GAS
SHIFT CON- VERTER
HYDROGEN SULFIDE AND CARBON DIOXIDE REMOVAL AND METHANATION
RECYCLE GAS TO GASIFIER
HIGH BTU GAS
CLAUS PLANT
SULFUR

Figure 29

BI-GAS Process Schematic

about 1700°F, and are quenched to 800°F by atomized water prior to separation in a cyclone. The synthesis gas (containing carbon monoxide, carbon dioxide, hydrogen, water, hydrogen sulfide, and methane) passes through a scrubber for additional cooling and cleaning. The clean gas, along with the desired amount of moisture, is sent to a carbon monoxide shift converter to establish the proper ratio of carbon monoxide and hydrogen required in the methanation process. Three process steps follow shift conversion: hydrogen sulfide removal, carbon dioxide removal, and methanation.

Hydrogasification (HYGAS)

The pilot plant is located in Chicago, Illinois. With the HYGAS process, several processing steps are required to convert coal to high-Btu gas. A diagram of the process is provided in Figure 30. Coal preparation involves crushing the coal to -14 mesh. Caking coal is pretreated in a fluidized bed at temperatures between 750°F and 850°F at an atmospheric pressure to destroy caking tendencies and produce a free-flowing coal. Non-caking coal is fed directly to the slurry tank. The coal is slurried in this tank with an aromatic recycle oil to form a thick slurry. This slurry is then pumped to 1000 psig and injected into the top section of the gasifier (slurry dryer) which contains a fluidized bed of hot coal particles. Oil is vaporized and removed, together with the hot gases passing upward from the lower stages of the gasifier. Vaporized oil is recovered for reuse by quenching the effluent from the gasifier.

Dry coal particles, at approximately 600°F from the slurry drying section, flow by gravity through a dipleg into a lift pipe. This lift pipe serves as the first stage of hydrogasification. In this stage, the heated coal comes in contact with a hot gas from the lower sections of the reactor. This gas contains methane, carbon oxides, hydrogen, and steam. The hydrogen chemically reacts with the more reactive part of the incoming coal, forming additional methane. Approximately one-third of the methane in the final product gas is produced in this step.

In the second stage hydrogasification section, the partially converted coal from the first stage mixes with the rising hydrogen-rich gas at about 1400-1700°F. Part of the hydrogen and steam react chemically with the coal, forming methane and carbon dioxides. Approximately one-third of the methane in the final product gas is produced in this step. Hot residual char is then transferred to the third stage. Here the steam and oxygen react with the char in a fluidized bed to produce a mixture of gases rich in hydrogen. This mixture is passed upward into the hydrogasification sections. Ash is removed from the bottom of the steam-oxygen zone.

The raw product gas leaving the top of the reactor at about 600°F is cooled and rinsed in a water quench, purified, and passed into a

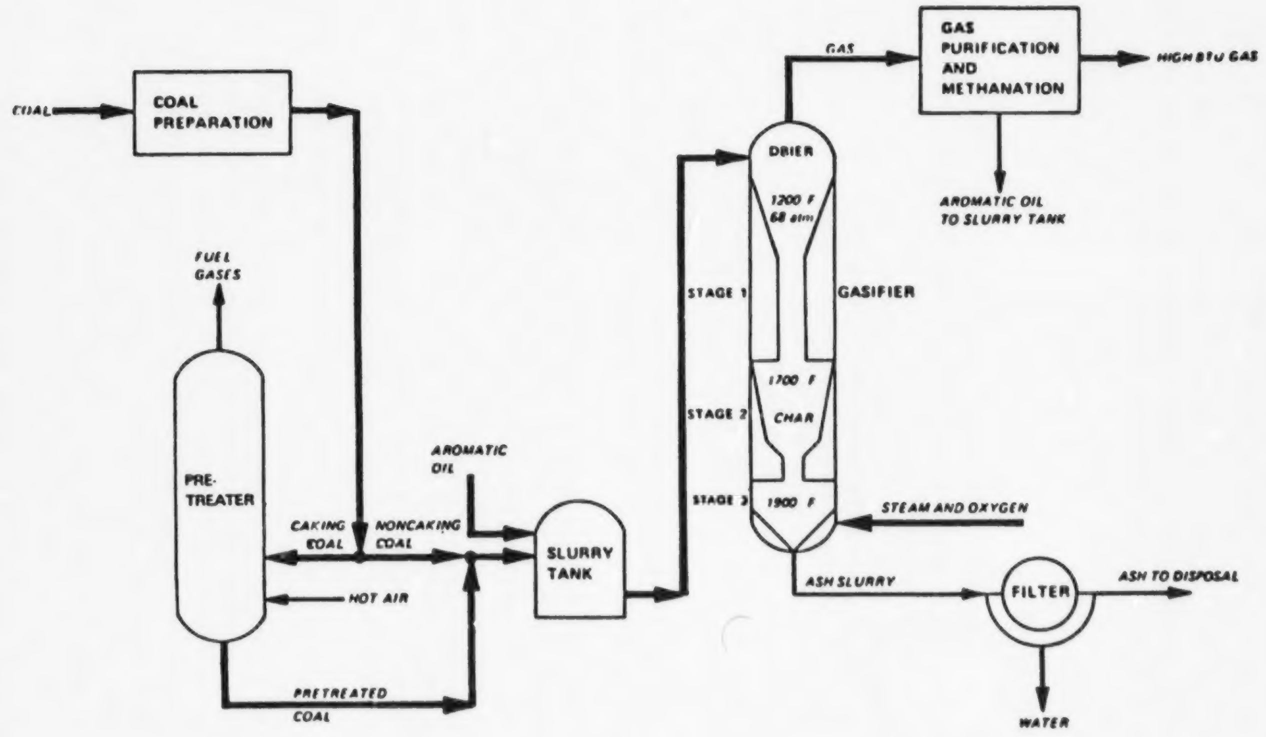

COAL
COAL PREPARATION
FUEL GASES
PRE-TREATER
CAKING COAL
NONCAKING COAL
HOT AIR
PRETREATED COAL
AROMATIC OIL
SLURRY TANK
STAGE 1
STAGE 2
STAGE 3
DRIER
1200 F
68 atm
1700 F
CHAR
1900 F
GASIFIER
STEAM AND OXYGEN
ASH SLURRY
FILTER
ASH TO DISPOSAL
WATER
GAS
GAS PURIFICATION AND METHANATION
HIGH BTU GAS
AROMATIC OIL TO SLURRY TANK

Figure 30

HYGAS Process Schematic

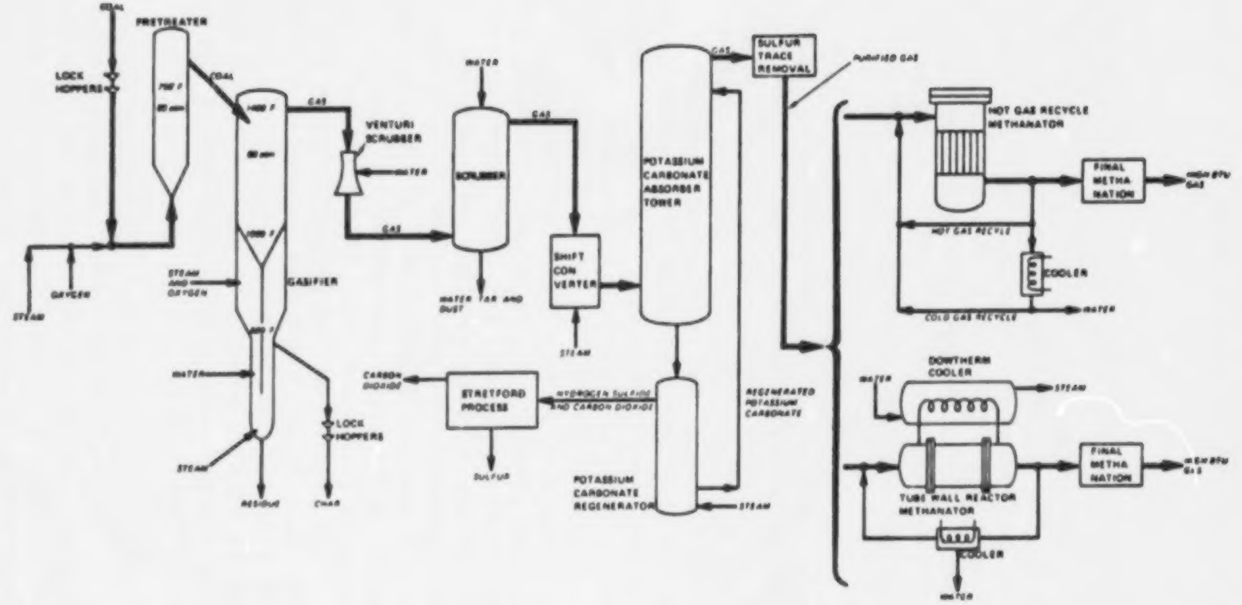
methanator. The ratio of hydrogen to carbon monoxide in the purified gas entering the methanator is adjusted to about three to one. The purified gas passes through a nickel catalyst at 800-900°F and is transformed to pipeline quality gas with an average heating value of 930 to 950 Btu per standard cubic foot.

Synthane

This DOE program is no longer being funded. The DOE pilot activities were located in Allegheny County, Pennsylvania. A key feature of the Synthane process is that pretreatment of caking coals is integrated with gasification. Another feature is that gas with a relatively high methane content is produced directly. A schematic of the Synthane process is provided in Figure 31. There are four major steps in the process: coal pretreatment, coal gasification, shift conversion and purification, and methanation.

Coal, crushed to -20 mesh, is dried, pressurized to approximately 40 atm., and is transferred into the fluidized-bed pretreater by means of high pressure steam and oxygen. Pretreatment prevents caking coals from agglomerating in the gasifier. The coal overflows from the pretreater into the gasifier fluidized bed through an injection pipe. Steam and oxygen enter the gasifier just below the fluidizing gas distributor. The gasification reaction occurs within the fluidized bed. Char flows downward into a bed fluidized and cooled with steam, and is removed with transport steam, slurried in water, and depressured through let down valves. In a commercial plant, this char can then be burned to produce process steam. The product gas, containing methane, hydrogen, carbon monoxide, carbon dioxide, ethane, and impurities, is passed through a venturi scrubber and a water scrubber to remove carry-over ash, char, and tars. The concentration of hydrogen and carbon monoxide in the gas is adjusted to a three-to-one ratio in a shift converter. The acid gases are absorbed in a hot-potassium carbonate (Benfield) scrubber. Carbon dioxide is reduced to two volume percent and sulfur is reduced to 40 parts per million. Regeneration of the potassium carbonate solution produces a hydrogen sulfide-rich gas, which is converted to elemental sulfur by the Stretford process. The remaining traces of sulfur in the product gas are removed by passing the gas through activated charcoal. The purified gas must be reacted catalytically to convert the hydrogen and carbon monoxide to methane.

Two methanation systems were installed in the pilot plant. One system operates isothermally with no recycle in a Tube Wall Reactor (TWR) in which the inside wall of the tube is coated with the catalyst and the heat of reaction is transferred to boiling Dowtherm on the outside of the tube wall. The other system is a Hot Gas Recycle (HGR) Reactor in which temperature is controlled by using a cooled recycle side stream of product gas. High pressure drop is avoided by coating parallel plates with catalyst, a low pressure drop configuration. The low level of CO



COAL
PRETREATER
LOCK HOPPERS
COAL
STEAM
OXYGEN
GAS
VENTURI SCRUBBER
WATER
GAS
WATER
SCRUBBER
GAS
STEAM AND OXYGEN
GASIFIER
WATER TAR AND DUST
WATER
LOCK HOPPERS
STEAM
RESIDUE
CHAR
SHIFT CON VERTER
STEAM
CARBON DIOXIDE
STRETFORD PROCESS
SULFUR
HYDROGEN SULFIDE AND CARBON DIOXIDE
POTASSIUM CARBONATE ABSORBER TOWER
POTASSIUM CARBONATE REGENERATOR
STEAM
REGENERATED POTASSIUM CARBONATE
GAS
SULFUR TRACE REMOVAL
PURIFIED GAS
HOT GAS RECYCLE METHANATOR
FINAL METHA NATION
HIGH BTU GAS
HOT GAS RECYCLE
COOLER
COLD GAS RECYCLE
WATER
DOWTHERM COOLER
WATER
STEAM
TUBE WALL REACTOR METHANATOR
FINAL METHA NATION
HIGH BTU GAS
COOLER
WATER

Figure 31

Synthane Process Schematic

that leaves the methanation as the catalyst deactivates will be converted in an adiabatic final methanator. The plant is currently in a protective standby status.

As previously indicated there are a number of high-Btu gasification processes that have received attention. Heat balance information for such processes are not readily available due to the current developmental and/or proprietary status of these processes. Reference 4 contains an estimated heat balance on a proposed combination of two gasifiers (e.g., Lurgi/BGC and Texaco) approach. Reference 4 indicates that the proposed combination gasifier concept is strongly synergistic in that the resulting balance between slurry water needs and phenolic liquor production eliminates the cost of liquor treatment as well as other operational and cost advantages. No claim was presented for an increase in overall system energy efficiency.

An estimated heat balance based on reference 4 is given in Table 18. Diagrammatically, this can be illustrated by the heat flow diagram, Figure 32. The provided heat balance is based on a plant with an output of over 250 billion Btu per day. The product gas has a heating value of 950 Btu/scf. The indicated design coal feed is 17,027 tons per day with an as-received Btu value of 24.47 million Btu per ton.

8.3 Application

Current

Currently, there is not a single commercial high-Btu gasification plant operating anywhere in the world. All current activities are in the research and development categories (5).

Projected

The successful development of a high-Btu gasification (from coal) technology would provide the means to produce a pipeline quality, pipeline compatible product from coal. The resulting gas would augment a decreasing amount of available natural gas. Undoubtedly, future use of high-Btu gasification technology would depend on a number of factors. These include:

1) The development of a viable technology,
2) The ability to satisfy environmental concerns, and
3) The ability to produce a pipeline quality product at an acceptable cost.

Assuming that an economic and environmentally acceptable technology can be developed, the high-Btu gasification of coal would permit the augmentation of natural gas with a synthetic product. The need for such a capability appears to be critical 15 to 20 years hence.

Table 18

Estimated Heat Balance for a 270 Billion Btu per day High-Btu Gasification Plant

	Btu/day (10^9 Btu's)	Percent of Total Energy Input
Product Gas		
285.3×10^6 scfd @ 970 Btu/scf	276.70	66.41
Electric Power Export		
Approximately 2400 Mwh_e per 24 hour period	8.17*	1.96*
Sensible Heat of Product Gas	0.33	0.08
System Losses		
Heat value of sulfur product	5.12	1.23
Carbon losses	4.67	1.12
Stack and boiler losses	4.70	1.13
Steam, ash disposal, and unaccounted	5.00	1.20
Electric motor and mechanical	2.50	0.60
Heat content of CO_2 waste gas	2.71	0.65
Heat Rejected		
Cooling tower and air cooler	106.75**	25.62**
Total Energy Input	416.65	100.0
(17,027 short tons/day @ 24.47×10^6 Btu/ton.)		

* Based on direct thermal equivalent

** Approximately 16% of total heat rejected is associated with production of export power

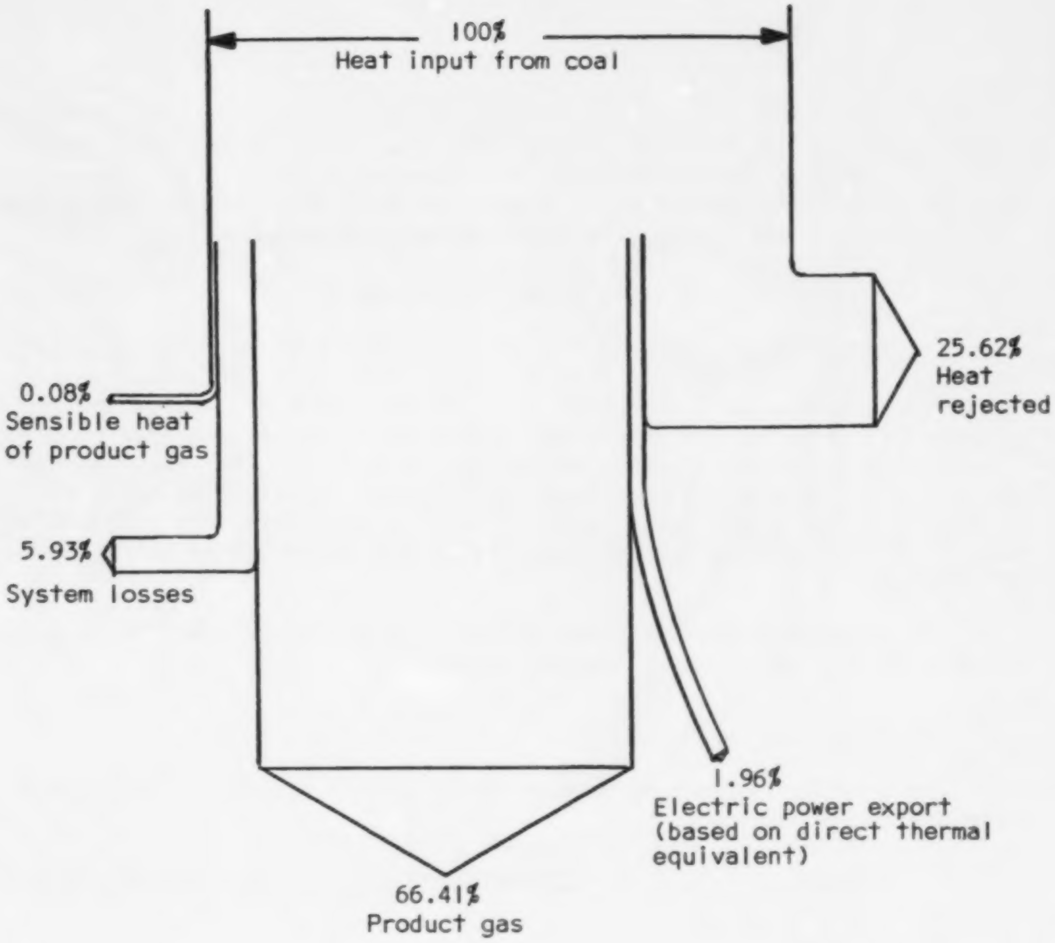

100%
Heat input from coal
0.08%
Sensible heat of product gas
5.93%
System losses
25.62%
Heat rejected
1.96%
Electric power export (based on direct thermal equivalent)
66.41%
Product gas

Figure 32

Estimated Heat Flow Diagram for High-Btu Gasification Plant

8.4 Environmental Considerations

As previously indicated, data applicable for environmental assessments of the overall gasification cycle is very limited. Any environmental assessments must be recognized as estimates until we can obtain data from on-line operating systems. Reference 2 indicates that data from pilot plants may not be representative of effluents that would be produced by a commercial plant.

Approximately 10 percent of the coal input to a gasification plant is used to generate steam. Combustion of this coal creates the environmental emissions generally associated with steam generation.

Other wastes (e.g., tar oils, phenols, solids) would be of different composition than wastes from conventional coal fired boiler steam generators. It must be emphasized that the handling of waste from a high-Btu coal gasification plant is an area where we have very limited information. The following presented material must be considered accordingly.

Identified Pollutants

This discussion addresses the environmental aspects associated with the gasification process and does not cover coal extraction and transportation. Reference 5 indicates that the data base for evaluating environmental, health, and safety aspects is very limited and that reported information is frequently contradictory. Reference 5 indicates that adverse health effects are particularly difficult to estimate, since no large scale plants are operational. The only available data on emissions and effluents are based on limited information collected at pilot plant operations.

The provided material, based mainly on unsupported analyses, are derived from the indicated referenced sources.

Air Emissions

The type and sources of potential air pollutants from coal conversion are as follows (6):

Pollutant	Process-Generated	Combustion-Generated
Particulate matter	X	X
Sulfur oxides	X	X
Reduced sulfur compounds	X	
Nitrogen oxides		X
Hydrocarbons	X	X
Carbon monoxide	X	X
Trace metals	X	X
Odors	X	
Other gases (including NH_3, HCN, HCl)	X	

Sulfur dioxide is emitted principally from the tailgas stream of the sulfur recovery plant and from stack gases of auxiliary systems requiring fuel oxidation. These include plant boilerhouse and miscellaneous fossil fuel fired process heaters.

Particulate matter can be released as a fugitive dust and as a process or combustion-based stack emission. Fugitive emissions have a potential for occurring at receiving, handling, and storage areas for coal, solid waste, and from leakage from process equipment elements. Process stack emissions would include the exhaust of pollution control equipment (e.g., scrubbers and precipitators). Fuel combustion would provide the potential source of particulate matter.

Nitrogen oxides emissions would result from fossil fuel firing of boilers. Hydrocarbon emissions could occur from liquid storage areas, system leaks, and from the evaporation of hydrocarbon liquids dissolved in cooling systems. Reduced sulfur compounds occur in the initial product stream of virtually all coal conversion processes.

Trace element emissions of such substances as mercury, beryllium, arsenic, and other heavy metals which are contained in coal in small amounts are expected in view of experience from coal fired boilers. In addition, other gaseous emissions, especially hydrogen cyanide and ammonia (as well as hydrogen chloride and gaseous odorants) may also be associated with coal conversion plants.

Liquid Effluents

Waste waters from coal conversion processes can originate from a number of sources. These include water of constitution, water added for stoichiometric process requirements, and water induced for gas scrubbing and by-product recovery. Such process waters come into contact with contaminants in coal and are likely to be a principal source of pollution. Table 19, taken from reference 6, indicates expected composition of wastewaters associated with one conversion approach (i.e., Synthane).

Table 19

Composition of Synthane By-Product Water

Pollutant	By-Product Water (mg/liter)
pH	7.9 - 9.3
COD	1,700 - 43,000
Ammonia	2,500 - 11,000
Cyanide	0.1 - 0.6
Thiocyanate	21 - 200
Phenols	200 - 6,000
Sulfide	N/D
Alkalinity (as $CaCO_3$)	N/D
Specific Conductance (as μmhos/cm)	N/D

N/D = not determined

Solid Waste

Past analyses have indicated the expectation that in a commercial plant, residue from the gasifier would be burned along with tars to raise steam for the overall process. Table 20, taken from reference 7, provides representative analyses of coals and associated chars from the Synthane process. The chars would contain some trace elements. It should be noted that problems may exist with burning tars due to residence time (in flame) and with SO_x stack gas cleaning when burning tar and char. Reference 2 indicated that in the past, consideration was given to solid waste disposal by means of burial in a mine. These waste materials would consist of ash from the boiler plant and gasifiers, coal wash plant waste (i.e., if wash plant is used), process sludge, and other waste. Undoubtedly, this whole disposal area requires additional effort. It should be noted that additional information for decision making is required so as to permit compliance with applicable environmental, health and safety regulations.

Regulatory Impacts

Currently, there is a substantial body of legislation that directly relates to the gasification of coal. There are Federal and state emission standards covering air, water, and solid waste. There exists legislation and regulations covering toxic substances, safe drinking water, occupational health and safety, protection of fish and wildlife and others. Any viable conversion technology would necessarily have to be consistent with the substantial body of environmental, health and safety legislation and regulations in being.

8.5 Performance

Current

Currently, there is not a single commercial high-Btu gasification plant anywhere in the world. Therefore, all projections are based on a technology still in the developmental stage.

Projected

It is difficult to provide confident estimates for coal conversion efficiencies. In addition, the definition of efficiency can vary depending on the included factors (e.g., only input coal or coal and supplemental energy).

Reference 2 indicates an efficiency range of 56-68 percent. Reference 8 indicates that for a 900 Btu/scf gas, the limiting efficiency is 77 percent and by 1990, a 75 percent value should be achievable. This is consistent with the estimated heat balance (Table 18) based on reference 4. In essence, we are dealing with a technology where a substantial amount of energy will be used and lost in the conversion process.

Table 20

Representative Proximate and Ultimate Analyses of
Coals and Chars, Weight Percent
(Synthane Process)

	Illinois No. 6 Coal	Western Kentucky Coal	Wyoming Subbituminous Coal	North Dakota Lignite	Pittsburgh Seam Coal
Coals:					
Moisture	8.3	4.3	18.1	20.6	2.5
Volatile matter	37.5	34.6	31.9	32.9	30.9
Fixed carbon	43.0	44.5	32.0	38.2	51.5
Ash	11.2	16.6	18.0	8.3	15.1
Hydrogen	5.3	4.7	5.4	5.7	4.7
Oxygen	15.9	10.9	30.3	32.6	9.3
Carbon	63.0	62.7	45.2	51.5	68.4
Nitrogen	1.1	1.2	0.6	0.7	1.2
Sulfur	3.5	3.9	0.5	1.2	1.3
Chars (from above coals):					
Moisture	0.8	1.2	0.5	1.2	1.4
Volatile matter	4.0	4.8	5.1	10.0	1.6
Fixed carbon	69.9	63.3	38.1	50.2	69.3
Ash	25.3	30.7	56.3	38.6	27.7
Hydrogen	1.0	1.0	1.0	0.9	1.0
Oxygen	1.3	1.1	1.2	0.0	1.7
Carbon	70.4	64.5	40.6	58.9	68.9
Nitrogen	0.6	0.7	0.4	0.2	0.5
Sulfur	1.4	2.0	0.5	2.0	0.2

8.6 Economics

Current

Since there is not a single high-Btu gasification plant in the world, economics can only be projections.

Projections

As with any sophisticated developing technology, the cost to produce a million Btu (MBtu) is, at best, an estimate. The estimated cost by DOE to produce a synthetic pipeline gas as of mid-1977 and based on coal costing one dollar per million Btu was \$4 - \$6 per million Btu (9). Undoubtedly, cost in current dollars will be high.

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9. Surface Oil Shale Processing

9.1 Overview

The oil shale resources in the United States probably exceed two trillion barrels of petroleum and of this amount, 25 to 35 percent is presently projected as being commercial. Most oil shale of projected commercial grade contains 20 to 50 gallons of oil per ton of rock. A large portion of the United States shale resource is in the range of 10 to 20 gallons per ton of rock with an insignificant amount of the resource base containing as much as 125 gallons per ton (1).

The most extensive high-grade deposits of domestic oil shale are in the Rocky Mountain region in the Green River Formation primarily in Colorado, Utah, and Wyoming, on land which is mostly in the public domain (1).

The two major routes for exploiting oil shale resources are (2):

1. Conventional mining followed by surface processing, and
2. In situ (in place processing).

In addition, there is modified in situ. Modified in situ involves removing some of the shale (e.g., by conventional mining) to increase the void volume in order to enhance the in situ processing. In modified in situ, recovered shale (e.g., by conventional mining) can be surface processed.

This section addresses convention (i.e., surface retorted) processes. In conventional oil shale processes, the following steps are performed:

- Mining the shale,
- Crushing the mined shale,
- Retorting the crushed shale, and
- Collecting and upgrading the crude shale and other by-products.

To date, a number of above ground retorting processes are in the advanced development stage. Even though shale oil has been produced commercially (on a small scale) for various periods of time since 1838, the future viability of an oil shale technology depends on many factors including:

- The demonstration of a modern commercial scale technology,

- The ability to satisfy environmental concerns, and

- The ability to produce an acceptable product at an acceptable price.

In this regard, there are many unknowns. These range from the ability to satisfy environmental concerns to the commercial scale cost to produce a barrel of oil from oil shale.

9.2 Process Description

Concept

Oil shale is a marl, a variety of limestone laced with organic matter (hydrocarbon) known as kerogen. Kerogen is a complex material composed mainly of carbon, hydrogen, oxygen, sulfur, and nitrogen. The kerogen molecule is large and heavy. Heating breaks the chemical network holding the heavy kerogen molecules together and "cracks" the individual large molecules into smaller molecules. This releases a liquid hydrocarbon mixture, the shale oil, that is the most valuable (3).

In conventional processes, the heating (retorting) takes place above ground. The conventional process is composed of four basic steps: mining the shale; crushing it to the proper size for the retort vessel; retorting the shale to release the oil; and refining the oil to bring it up to a high-quality product. The shale can be mined underground or on the surface depending on the nature of the deposit. The minimum thickness of a shale seam for commercial utilization is considered to be about 30 feet, but thicker seams are preferred (3).

After the shale is crushed to the right topsize, it is fed into a retorting vessel and heated to between $800^{\circ}F$ and $1000^{\circ}F$ to decompose the kerogen. In practice, on the order of 75 percent of the kerogen is separated from the rock at these temperatures (3).

Different retorting processes apply heat to the shale in different ways. The heat carrier can be either a gas or noncombustible solid such as sand or ceramic balls. The oily vapor produced as the kerogen decomposes during the retorting is condensed to form the raw shale oil. This raw shale oil is subsequently upgraded to produce a more marketable product. If gas is produced in the retorting operation, it can be used for process purposes (e.g., to produce electric power) and/or a pipeline quality gas.

Detail

Conventional (above ground retorting) oil shale processes basically provide for the following (2, 3):

1. Mining the shale,
2. Crushing the mined shale,
3. Retorting the crushed shale,
4. Collecting the crude shale oil and other by-products, and
5. Upgrading the crude oil and possibly other by-products.

Currently, there are several above ground retorting processes that are in the advanced development stage. These include:

- The Union Oil Company Retort B process that employs a vertical gas-recycle retort.
- The Paraho Development Corporation hot gas process that employs a vertical gas combustion kiln based on a design used for many years to process limestone.
- The Superior Oil hot gas method that employs a circular gas-combustion retort.
- The Lurgi-Ruhrgas modified coal carbonization technique that uses sand or recycled shale ash heated to above 900°F to retort the shale.
- The TOSCO II process that uses ½-inch ceramic balls heated to above 1000°F to transfer heat to the crushed shale.

The Oil Shale Corporation (TOSCO), in conjunction with other joint venture participants (called the Colony group), have demonstrated their retort process technology at Parachute Creek, Colorado, in a 1000 tons/day semi-works plant. TOSCO has designed a full-scale 66,000 tons/stream day commercial plant that would produce 47,000 barrels per day of low sulfur fuel oil and 4,300 barrels per day of LPG. The plant (TOSCO II) would be located on the Dow West property of the Middle Fork of Parachute Creek, with spent shale disposal in the nearby Davis Gulch. Current plans are for construction of full-scale commercial plant to commence in early 1984 with completion early in 1987. Details of the TOSCO II process follow (4, 5).

The TOSCO II retort is an externally-heated reactor that uses hot ceramic balls to heat the shale to pyrolysis temperature in a horizontal, rotating kiln. The shale, crushed to less than one-half inch size, is fed into a fluidized-bed where it is preheated by hot combustion gases from a separate ball heater. After preheating, the shale is moved into the reactor and mixed with half-inch diameter heated ceramic balls from the ball heater. The heat in these balls transfers to the shale, effecting pyrolysis. The oil, steam, and gases are given off as a mist, which is fed to a fractionator for product recovery. The spent shale and ceramic balls are discharged from the pyrolysis drum and separated by a trommel screen. The balls are returned to the ball heater, and the spent shale is removed for disposal (6).

A fractionator separates the oil from gas and waste contained with the hydrocarbon vapors feeding the fractionator; some of the gas from the fractionator is burned to heat the balls in the ball heater. Since no combustion takes place in the reactor vessel, the resulting gas has a higher energy content and the oil a lower viscosity than that from an internally heated retort. These features, and the reactor's ability to handle fine particles, are advantages of the TOSCO II process (6).

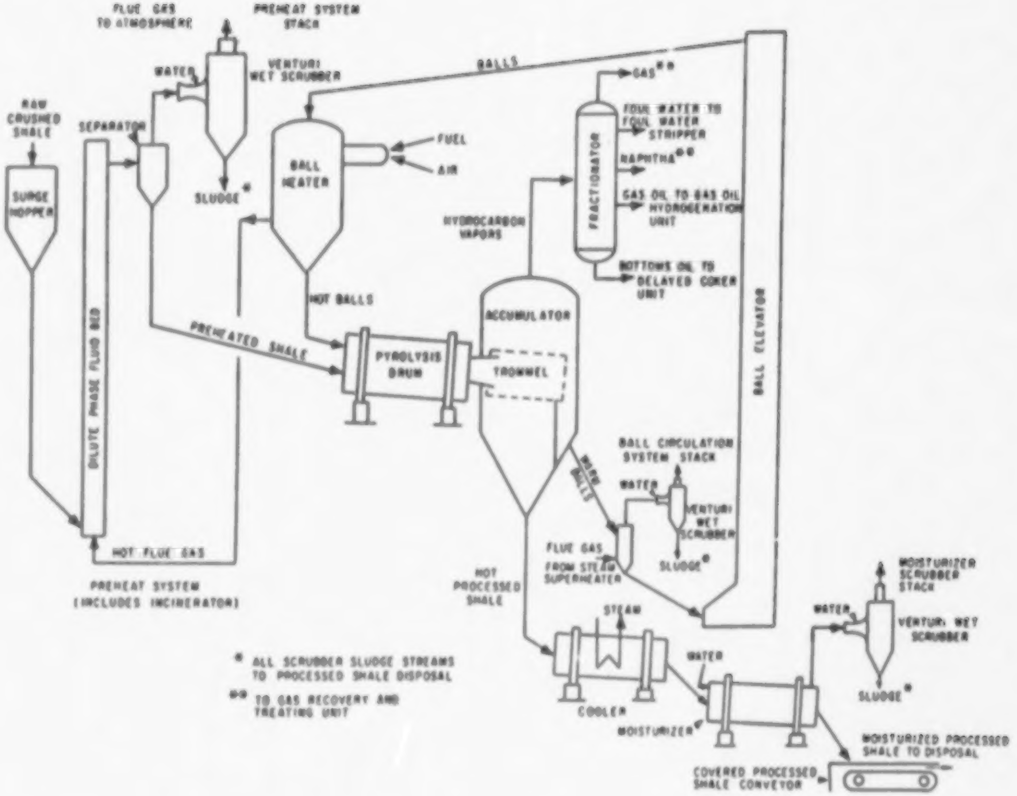
The TOSCO II commercial plant will include a conventional underground room-and-pillar mine. Primary crushing of the run-of-mine shale will be carried out at the mine portal bench. The coarse ore product will be transported by conveyor to the final crusher at the plant site. The product on final crushing will be ½-inch topsize and fed to the TOSCO II retort unit and oil recovery equipment. The flowsheet for a single unit (one of six) is shown in Figure 33 (5).

As previously indicated, the minus ½-inch oil shale is first preheated to about 500°F with flue gas from the ball heater. The preheated shale is fed to a horizontal rotating retort (pyrolysis drum), together with approximately 1.5 times its weight in hot ceramic balls from a ball heater. This raises the temperature of the shale to pyrolysis temperature (900°F) and converts its contained organic matter to shale oil vapor. The shale oil vapors are fed to a fractionator for hydrocarbon recovery. The mixture of balls and denuded shale are discharged through a trommel, in order to separate the balls from the shale. The warm balls are purged of dust with flue gases from a steam preheater (5).

The dust-free warm balls are returned to the ball heater via a ball elevator. They are then reheated to about 1300°F using in-plant fuel and then recirculated to the pyrolysis drum (5).

The hot processed shale is cooled, moisturized and deposited in a disposal site. The shale oil hydrocarbon vapors from the pyrolysis drum are separated into water, gas, naptha, and gas oil, and bottom oil in a fractionator. The foul water is stripped of H_2S and NH_3 and reused and the other products are upgraded prior to shipping or used for process purposes (5).

An estimated energy balance for a commercial scale TOSCO II facility is contained in reference 7. The reference 7 energy balance assessment covers both the retorting process and the resulting product upgrading facilities. An estimated heat balance based on reference 7 is given in



RAW CRUSHED SHALE
SURGE HOPPER
DILUTE PHASE FLUID BED
SEPARATOR
FLUE GAS TO ATMOSPHERE
PREHEAT SYSTEM STACK
WATER
VENTURI WET SCRUBBER
SLUDGE *
BALLS
BALL HEATER
FUEL
AIR
HOT BALLS
PREHEATED SHALE
PYROLYSIS DRUM
TROMMEL
ACCUMULATOR
HYDROCARBON VAPORS
FRACTIONATOR
GAS **
FOUL WATER TO FOUL WATER STRIPPER
NAPHTHA **
GAS OIL TO GAS OIL HYDROGENATION UNIT
BOTTOMS OIL TO DELAYED COKER UNIT
BALL ELEVATOR
WORN BALLS
BALL CIRCULATION SYSTEM STACK
WATER
VENTURI WET SCRUBBER
SLUDGE *
FLUE GAS FROM STEAM SUPERHEATER
HOT FLUE GAS
PREHEAT SYSTEM (INCLUDES INCINERATOR)
HOT PROCESSED SHALE
STEAM
COOLER
WATER
MOISTURIZER
MOISTURIZER SCRUBBER STACK
WATER
VENTURI WET SCRUBBER
SLUDGE *
MOISTURIZED PROCESSED SHALE TO DISPOSAL
COVERED PROCESSED SHALE CONVEYOR
* ALL SCRUBBER SLUDGE STREAMS TO PROCESSED SHALE DISPOSAL
** TO GAS RECOVERY AND TREATING UNIT

Figure 33

Pyrolysis and Oil Recovery Unit TOSCO II Process

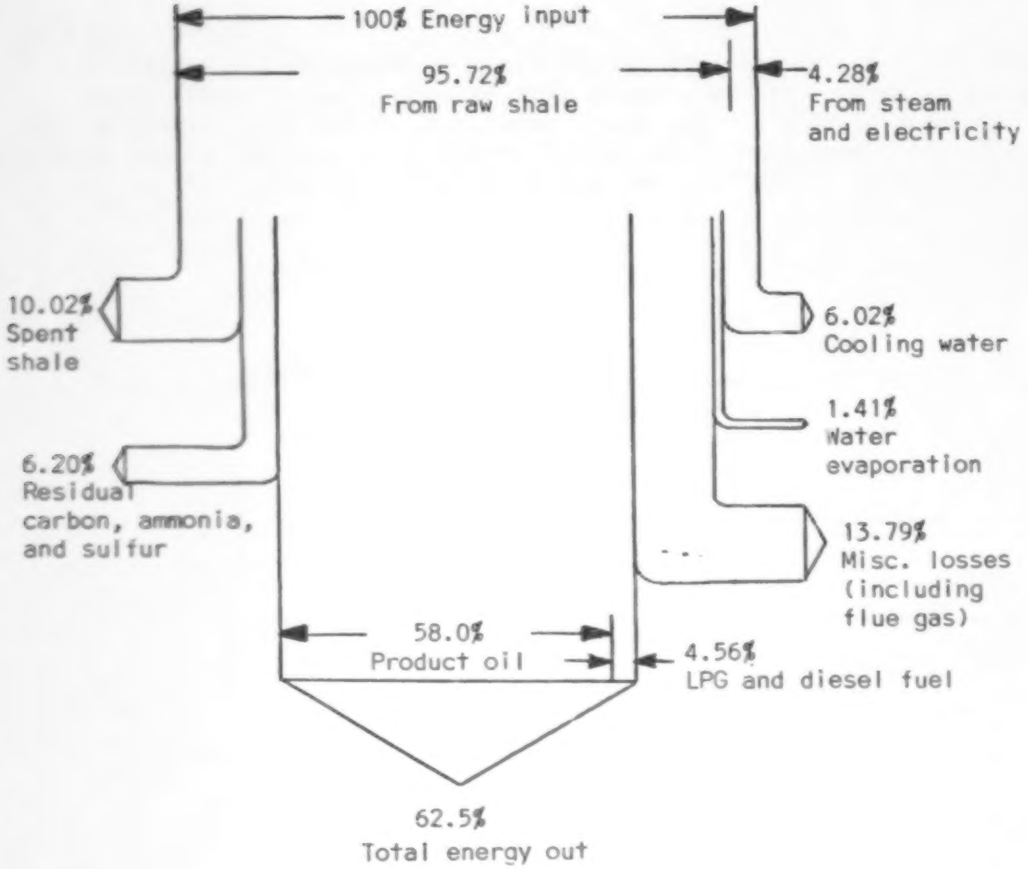
Table 21. Diagrammatically this can be illustrated by Figure 34. It should be noted that the provided heat balance is an estimate, there being uncertainty as to the exact composition of the input stream and the yields and composition of the output stream. The provided energy balance is in terms of energy flow per hour of plant operation.

Table 21

Estimated Energy Balance For a TOSCO II Plant
Producing 47,000 BPSD* Upgraded Shale Oil
From 35 Gallons Per Ton Oil Shale

	Btu/hour (10^9 Btu's)	Percent of Total Energy Input
Product Output		
Product oil	10.30	58.00
LPG	0.70	3.94
Diesel fuel	0.11	0.62
System Losses		
Spent shale and moisture	1.78	10.02
Residual carbon (coke)	0.93	5.24
Ammonia	0.11	0.62
Sulfur	0.06	0.34
Cooling water	1.07	6.02
Water evaporation on shale	0.25	1.41
Losses (including flue gas heat)	2.45	13.79
Energy Input	17.76	100.0
Raw shale	17.00	95.72
Steam	0.53	2.98
Electrical energy	0.23	1.30

* BPSD = barrels per stream day



100% Energy input
95.72%
From raw shale
4.28%
From steam
and electricity
10.02%
Spent
shale
6.02%
Cooling water
1.41%
Water
evaporation
6.20%
Residual
carbon, ammonia,
and sulfur
13.79%
Misc. losses
(including
flue gas)
58.0%
Product oil
4.56%
LPG and diesel fuel
62.5%
Total energy out

Figure 34

Estimated Heat Flow Diagram For TOSCO II Plant

9.3 Applications

Current

Shale oil has been produced commercially for various periods of time in eleven countries since the initiation of shale oil operations in France in 1838. In Canada and the Eastern United States, a very small industry was operating in 1860 but disappeared when petroleum became plentiful. Currently, the only commercial production is in Russia (Estonia) and China with a combined production of approximately 150,000 barrels per day. All other shale industries (i.e., in other countries) succumbed because of the inability to compete with petroleum fuels. All production to date has generally occurred in retorts that would not be considered of commercial size for U. S. operations (2, 8).

Projected

The successful development and demonstration of a commercial scale shale oil production technology would provide a valuable alternative for the acquisition of liquid fuels. The ability to produce oil from oil shale would provide the potential means to produce liquid fuels from our vast oil shale resources and thereby reduce our dependence on imported and domestic petroleum products. The commercial scale development and future use of an oil shale technology are dependent on many factors. These include:

- The demonstration on a commercial scale of a viable technology,
- The ability to satisfy environmental concerns, and
- The ability to produce a commercially acceptable product at an acceptable cost.

9.4 Environmental Considerations (3, 8)

The Environmental Protection Agency, the Department of Energy, other governmental agencies, and other groups are studying the environmental aspects of shale oil development. Currently, there remain a number of unanswered environmental questions. It may not be possible to provide a meaningful environmental determination until experience with one or possibly more operating plants are acquired. The technologies are just too new, the effected ecologies are not well understood, and the scale of operation is too massive to be able to predict (with a reasonable degree of confidence) the effect of an oil shale industry. In addition, envisioned environmental controls for the oil shale industry are subject to large uncertainties.

The most significant problems and uncertainties are associated with impacts on air and water quality, waste management and occupational health and safety aspects.

Identified Pollutants

Air Emissions

Atmospheric emissions can arise from several activities or operations during oil shale processing. The major source of SO_2, NO_x, and CO is fuel combustion for process heat; SO_2 is also emitted in the tail gases of sulfur recovery operations. The use of fuel oils in mobile equipment and in explosives will result in emissions of CO and NO_x. Hydrocarbons are present in both combustion emissions and in product storage tank vapors. Emissions of particulate matter can result from blasting, raw and spent shale handling and disposal, raw and spent shale dust in process gas stream, fuel combustion, and site activities which generate fugitive dust.

Particulate emissions from fuel combustion and fugitive dust from spent shale handling and disposal can contain polycyclic organic material (POM) and certain trace metals. Gaseous ammonia, hydrogen sulfide, and volatile organics may be released during moisturizing and subsequent cooling of retorted shale. Catalyst materials may release particulate matter containing trace metals to the atmosphere during regeneration, handling, or final disposal.

Actual SO_2 emission associated with individual retorting processes will depend upon the degree of sulfur removal accomplished for in-plant fuels, the extent of on-site shale oil processing, and the degree of control applied to sulfur recovery tail gases. Combustion of any hydrocarbon fuel will produce oxides of nitrogen when air containing nitrogen is used as the source of oxygen. In addition, organic nitrogen contained in the fuel can be partially oxidized to NO and NO_2. In general, those processes which require small-size shale feed (e.g., TOSCO II) will have more uncontrolled particulate emission during crushing and raw shale operations than processes which require large feed.

Site use activities which may generate fugitive dust generally are not process specific. The use of open pit versus underground mining will be the largest factor determining total fugitive emissions associated with extraction of oil shale. Overall fugitive dust emissions may present more of a problem for the TOSCO II process than for some other processes. Ore storage and handling and disposal of the fine TOSCO II retorted shale are potential fugitive sources.

The largest source of CO in an oil shale operation is mobile equipment used for mining and transport. The quantity of such emissions is a function of mining method and haul distances rather than retorting process.

The pyrolysis of essentially any type of organic material produces a certain amount of POM, and oil shale kerogen is no exception. Generally, POM compounds have a low volatility and will be associated with high boiling liquid or solid products or particulate matter. And, although POM is known to be present in carbonaceous retorted shales, the biological availability and potential hazard of such material is not accurately known at present.

Release of POM to the atmosphere during oil shale processing can occur via three major pathways:

(1) Handling and disposal of retorted shale - fugitive particulates and possible volatilization of hydrocarbons.

(2) Combustion of shale derived oils containing POM.

(3) Flue gases containing entrained retorted shale particulates, along with retort gas or spent shale coke combustion products.

Oil shale contains trace amounts of many elements. However, for elements other than Si, Fe, Al, Ca, Mg, and K, the concentrations in oil shale are less than generally found in coal. In addition, conditions during retorting are not severe enough to volatilize most metallic and heavy elements. With notable exceptions such as arsenic (As) and possibly antimony (Sb), most trace elements (e.g., nickel (Ni), vanadium (V), molybdenum (Mo)) remain with the spent shale, or are found as components of raw and spent shale solids entrained in retort gases and in raw shale oil. Arsenic in raw shale apparently forms a range of volatile oil soluble compounds (perhaps organic arsines) during retorting, and appears in raw shale oil and all condensible oil fractions. If not removed during upgrading, arsenic will be present in shale oil combustion products.

Metals and their compounds are used as catalysts (Ni, Co, Mo, Cr, Fe, Zn) for hydrotreating, de-arsenating, sulfur recovery, and trace sulfur removal. Emissions of particulate matters containing catalyst metals can occur either during on-site regeneration or during handling and disposal. Catalyst use is not unique to shale oil processing, and much information and experience in preventing hazardous emissions can be borrowed from the petroleum and related industries.

Solid and Liquid Effluents

Construction, mining, and site use activities may potentially result in increased sediment and dissolved solids loading in surface run-off and receiving streams. This indirect source of potential water pollution is not unique to oil shale extraction and processing but may require careful control due to the magnitude of site activities. Collection and impoundment of run-off may be necessary.

The need to process 1 to 3 tons of shale per barrel of oil results in a major solid waste disposal problem regardless of whether surface or in situ retorting is employed. A principal impact will be the necessary storage of overburden on refuse from open pit and room-and-pillar mining. Large volumes of waste material must be disposed of in a satisfactory manner. If the overburden and refuse have properties toxic to the existing surroundings, vegetation and ecosystem, then the technology must include control of these effects.

Aqueous wastes from oil shale processing can be broadly categorized as originating from direct or indirect sources. Direct sources are wastewaters generated from unit operations and/or processes, including wastewater from retorting operations; wastewater from upgrading operations; water from air emission control and gas cleaning systems; cooling water and boiler water blowdowns; water treatment systems; mine dewatering wastewater; and sanitary wastewaters. Indirect sources include: leachate from retorted shale disposal areas; run-off and erosion resulting from construction and site use activities; and run-off from mining and transport activities.

Water is a direct product of oil shale retorting, resulting from the step in the release of free and inorganically bound water from raw shale, and combustion of organic material in shale. From 1 to 8 gallons of water are commonly produced per ton of input shale feed to a surface retort, depending on the retorting process and the composition of the shale processes.

This water can separate partially from crude shale oil during storage, and/or can appear in aqueous waste streams of shale oil upgrading operations. Water remaining in retort gases after oil separation can be condensed during cooling or gas cleaning operations, or can appear in the flue gas stream from retort gas combustion. Water separated from crude shale oil contains mainly ammonia, carbonate and bicarbonate, sodium, sulfate, chloride, and dissolved or suspended organic compounds (phenolics, amines, organic acids, hydrocarbons, mercaptans). Smaller quantities of calcium, magnesium sulfides, and trace elements may also be present, along with suspended shale fines. Water condensed from retort gases contains primarily ammonia and carbonates, with traces of organic substances and sulfur containing compounds.

The quality of wastewaters from an upgrading operation varies with the level of on-site upgrading or refining utilized. In general, a full-scale refining operation may include any of the following wastewater streams: oily cooling water, process water, and wash water.

Wastewaters are also collected during retort gas cleaning, tailgas cleanup, and foul water stripping. Major constituents in such waters are shale dust particulates, hydrocarbons, H_2S, NH_3, phenols, organic acids, and amines. Other constituents such as thiosulfate and thiocyanate may also be present.

Approximately 45 to 50 percent of the water required for an oil shale plant is expected to be used for moisturizing of retorted shale. Much of this water requirement will be supplied by minewater and process wastewaters. Because of the large quantities of water utilized and the exposure of retorted shale to rain and snowfall, a source of indirect water pollution may occur via leaching or run-off from retorted shale piles. However, the bulk of the water applied to retorted shale is expected to be held in capillarity or to be bound as simple hydrates. The suspended and dissolved constituents of wastewaters applied to retorted shale are expected to be partially immobilized by physical adsorption and/or chemical reaction with retorted shale. Leaching experiments in the laboratory and with small plots indicate that inorganic salts - Na, Mg, SO_4, Cl - may be leached from retorted shales. Small quantities of organic substances and trace elements are also water soluble.

Regulatory Impacts

Each oil shale technology and resulting commercial implementation will have to be evaluated separately as to regulatory impacts. Because of the differences in technologies and in state and local regulations, siting of a major oil shale facility must be addressed on a case-by-case basis.

The oil shale industry must comply with regulations and standards including requirements of the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Federal Nonnuclear Energy Research and Development Act, and the National Environmental Policy Act as well as applicable State laws.

Undoubtedly, the oil shale industry will benefit from the experience of the petroleum industry in dealing with complex organic substances and new processes while complying with governing statutes.

9.5 Performance

Current

Even though an estimated heat balance (for a given process) and thereby an efficiency value is provided, it should be recognized that, currently, there are no commercial scale shale oil extraction and processing facilities in the United States. There have been some small scale experimental efforts and small scale demonstration of some process elements (e.g., a specific retort). Therefore, there are no performance values that can be applied to a commercial scale plant.

Projected

It is difficult to provide confident estimates of operating efficiencies of future shale oil facilities. In this regard, a given shale oil project could have various efficiency values depending on the specific definition. Efficiency values could be based on energy contained in resources in place or on the energy content of the shale into the retorting facility. In addition, efficiency values will depend on what system input and product output energy components are considered.

9.6 Economics

Current

There are no commercial scale oil shale processing facilities currently in operation in the United States.

Projected

The oil shale companies themselves are aware of the technological and economic uncertainties. One company recently stated that no one really knows what any of the available oil shale technologies will do or what they will cost in dollars per barrel until plants are built and operating and cost data collected (1). Even though there is considerable uncertainty, reference 10 does contain an assessment of economic and financial considerations.

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10. In Situ Oil Shale Processing

10.1 Overview

The oil shale resources in the United States probably exceed two trillion barrels of petroleum and of this amount 25 to 35 percent is presently projected as being commercial. Most oil shale of projected commercial grade contain 20 to 50 gallons of oil per ton of rock. A large portion of the United States shale resource is in the 10 to 20 gallons of oil per ton of rock range. An insignificant amount of the resource base contains as much as 125 gallons per ton (1).

The most extensive high-grade deposits of domestic oil shale are in the Rocky Mountain Region in the Green River Formation primarily in Colorado, Utah, and Wyoming, on land which is mostly in the public domain (2).

The two major routes for exploiting oil shale resources are:

1) Conventional mining followed by surface processing, and
2) In situ (in place processing).

In addition, there is modified in situ. Modified in situ involves removing some of the shale (e.g., by conventional mining) to increase the void volume in order to enhance the in situ processing. In modified in situ, recovered shale (i.e., via conventional mining) can be surface processed.

This section addresses in situ retorting (including modified in situ). True in situ processes involve (1) formation fracturing via vertical well bores to create permeability without mining or removal of material followed by undergound retorting and (2) underground retorting via well bores utilizing natural permeability where it may exist. No underground material is removed by any means to create additional void space for fracturing or rubbling except by the drilling/underreaming process (3).

The modified in situ process involves mining or removing by some other means (such as leaching or underreaming) up to 40 percent of the shale (i.e., in the retorting sector) so the void volume and permeability can be increased before retorting. The remaining oil shale is then explosively fractured into the void volume and combustion or hot-gas retorted. In the case of leached shale, the shale is not fractured, but hot-gas retorted. The mined shale fraction can be surface retorted (3, 4).

Currently, a number of in situ processes are receiving attention with a goal of demonstrating a viable commercial capability. The commercial scale development and degree of product market penetration will depend on numerous factors. These include:

1) The demonstration of a modern, viable commercial scale technology,

2) The ability to satisfy environmental concerns, and

3) The ability to produce an acceptable product at an acceptable price.

In this regard there are many unknowns. These range from the ability to acquire a viable in situ technology to achieving an acceptable environmental status. It is expected that the cost to produce a barrel of shale oil from an in situ process would be less than for a surface retorted process (i.e., assuming the achieving of a viable technology).

10.2 Process Description

Concept

Oil shale is a marl, a variety of limestone laced with organic matter (hydrocarbon) known as kerogen. Kerogen is a complex material composed mainly of carbon, hydrogen, oxygen, sulfur, and nitrogen. The kerogen molecule is large and heavy. Heating breaks the chemical network holding the heavy kerogen molecules together and "cracks" the individual large molecules into smaller molecules. This releases liquid hydrocarbon, some combustible gases, and a coke-like residue. It is the liquid hydrocarbon mixture, the shale oil, that is the most valuable (4).

In "true" in situ processing, a central well is first drilled into the bed of shale. Several other wells are then drilled in a pattern around the central well. Explosive charges are placed in the wells and detonated to fracture the surrounding shale. Sometimes the shale is fractured by pumping water into the wells under very high pressure. This fracturing process is necessary to create pathways (void spaces) in the normally impermeable shale so as to permit heat transfer. For a given in situ site, about 30% of the shale volume has to contain void spaces for enough combustion to take place to decompose the kerogen (4).

Once the shale is fractured, it is ignited by a flame from compressed air and a combustible gas pumped into the central well. The hot combustion gases circulate along the pathways in the fractured shale, heating it to retorting temperatures and releasing the gas and oil from the kerogen. After a few hours, the externally-fed gas is shut off, but compressed air continues to be fed to the burn zone where combustion is sustained by the carbon residue that remains as the shale is retorted (4).

The gas produced in the retorting process is withdrawn from a well down-stream from the central injection well. Some of this gas is recirculated to the central well to aid combustion. The vapor produced in in situ retorting condenses to liquid in a sump at the base of the shale area and is pumped to the surface.

In a "modified" version of in situ recovery, 20 to 40% of the lower portion of the shale bed is first mined (by conventional methods) or otherwise removed. This leaves a void space beneath the shale. The shale is then fractured with explosives, filling the mined-out space with shale rubble. The rubble column is ignited, retorting the shale in place, as in the "true" in situ method, to produce gas and oil. The shale extracted (e.g., by conventional methods) can be retorted by conventional surface processes.

The oil from in situ processing has essentially the same characteristics as the oil retorted on the surface and has to be processed to remove impurities before being used as refinery feedstock (4).

Details

True In Situ (5)

The true in situ shale oil recovery process is characterized by fracturing techniques that require no mining or removal of major amounts of oil shale. The fractured oil shale bed can be retorted by two general methods. The shale can be ignited at the bottom of the injection well and combustion sustained by air injection, in which case hot combustion gases retort the shale. In some cases, it is advantageous to supplement the air supply by injecting propane, recycled gas or some other fuel to enhance combustion. In the second method, energy for retorting the shale can be supplied by injecting heated gases. The gases considered for use in this process are steam, natural gas, nitrogen, and others.

In either method, products of retorting are recovered from the production well. Liquid products collected in the bottom of the well can be pumped to the surface. Liquid entrained in the exit gas stream can be separated and collected on the surface. Depending on the heating value of the gas stream, it can be used as recycle gas, burned as a source of fuel on the surface, or discarded through a flare to prevent pollution. The true in situ concept is indicated by Figure 35. This concept of processing oil shale is most likely to be applied to shales deposited in thin beds, possibly interspersed with barren rock.

Modified In Situ

The difference between these processes and true in situ retorting methods is that between 20 and 40 percent of the oil shale or other minerals are mined or otherwise removed from within the retort to provide the void space for enhanced permeability when the remaining shale is rubblized, as previously discussed. If mined shale is oil rich, it will

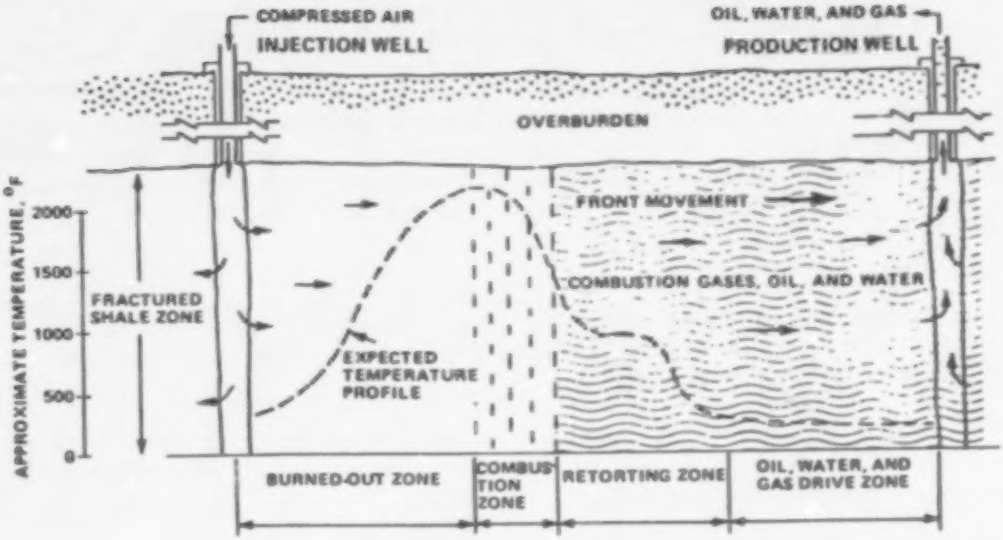
COMPRESSED AIR
INJECTION WELL
OIL, WATER, AND GAS
PRODUCTION WELL
OVERBURDEN
APPROXIMATE TEMPERATURE, °F
2000
1500
1000
500
0
FRACTURED SHALE ZONE
FRONT MOVEMENT
COMBUSTION GASES, OIL, AND WATER
EXPECTED TEMPERATURE PROFILE
BURNED-OUT ZONE
COMBUSTION ZONE
RETORTING ZONE
OIL, WATER, AND GAS DRIVE ZONE

Figure 35

True In Situ Retorting

be sent to surface retorting; but if it is low-grade shale, it will probably be discarded. This can greatly influence mine designs and detailed development plans. Wells are drilled and prepared prior to fracturing the shale. After the oil shale is fractured through explosive techniques, a porous medium remains and retorting is begun.

Four general concepts of modified in situ techniques can be identified (5):

1) Vertical modified in situ with partial mining in which the relative dimensions of the retort are larger in the vertical direction than in the horizontal, such as a column.

2) Horizontal modified in situ with partial mining in which the relative dimensions are larger in the horizontal direction than in the vertical, such as a bed.

3) Modified in situ retorting of a zone in which minerals contained in the shale have been removed by naturally occurring groundwater (leached zone in Colorado) or by solution mining.

4) Horizontal modified in situ retorting of a rubblized oil shale bed that has been prepared by explosive detonation resulting in noticeable surface uplift.

Modified techniques that require partial mining followed by massive rubblization are believed to offer the most promise for deeper and very thick shale deposits. In these deposits the vertical configuration is most useful. A horizontal technique will be more useful in somewhat thinner deposits or as a secondary recovery method in a previously worked mine (5).

Collected crude oil must be processed to remove water and other contaminants and then further upgrading (e.g., removal of deleterious materials and viscosity alteration) before pipelining and before entering conventional refinery streams.

A number of modified in situ processes are currently receiving substantial attention with a goal of demonstrating a viable commercial capability. These include (4, 6):

1) The Occidental Oil Company's "modified" vertical in situ process in which a rubbled column of broken shale is retorted to produce oil and a combustible gas.

2) The Rio Blanco modified in situ method involves mining out a relatively large underground retort void space. After removal of the material from underground, the retort is rubblized and burned to produce oil. The mined-out material is surface retorted.

3) The Geokinetics process in which oil shale is extracted possibly from oil shale beds under relatively thin overburden using a horizontal modified in situ technique.

Details on the Occidental modified in situ process follow (7):

The Occidental modified in situ shale oil recovery scheme is covered by a U. S. Patent. The system was tested in excess of one year in a commercial size in situ retort with a total production in excess of 27,000 barrels of crude oil.

The modified in situ process for shale oil recovery consists of retorting a rubblized column of broken shale, formed by expansion of the oil shale into a previously mined out void volume. The process involves three basic steps. The first step is the mining out of approximately 20 to 25% of the oil shale deposits (preferably low grade shale or barren rock), either at the upper and/or lower level of the shale layer. This is followed by the drilling of vertical longholes from the mined-out room into the shale layer, loading these holes with an ammonium nitrate-fuel oil (ANFO) explosive, and detonating it with appropriate time delays so that the broken shale will fill both the volume of the room and the volume of the shale column after blasting. Finally, connections are made to both the top and bottom and retorting is carried out (Figure 36).

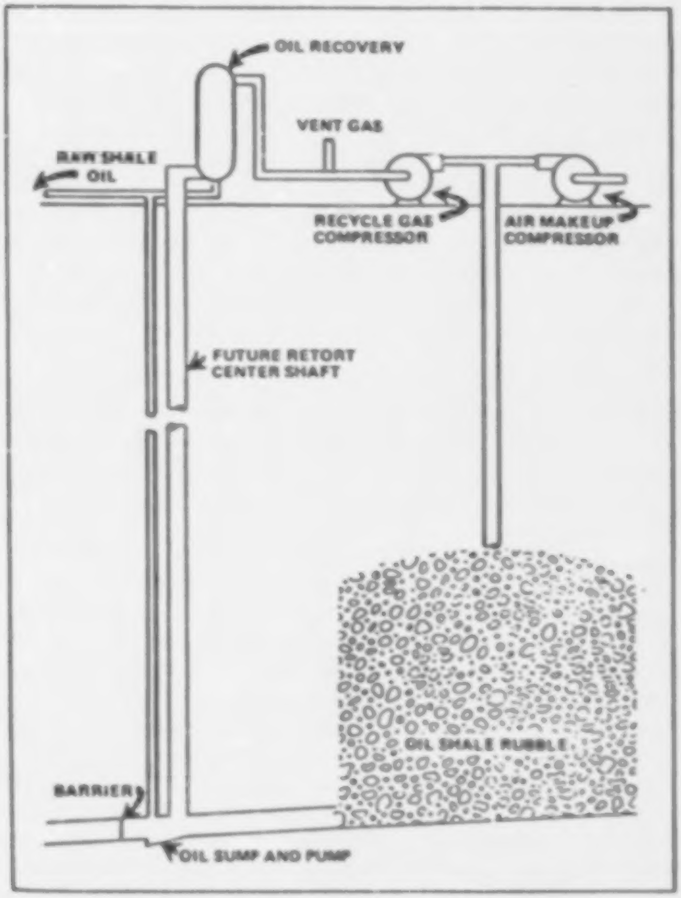
OIL RECOVERY
VENT GAS
RAW SHALE OIL
RECYCLE GAS COMPRESSOR
AIR MAKEUP COMPRESSOR
FUTURE RETORT CENTER SHAFT
OIL SHALE RUBBLE
BARRIER
OIL SUMP AND PUMP

Figure 36

Occidental Oil Shale Process Retort Operation

In the Occidental scheme, both the size of the retorting chamber and the thickness of the walls have an important impact on the fraction of the cross section of the shale formation available for retorting. With

40 feet thick walls, the cross section of the shale formation available for retorting would be 56% for 120-ft square retorting chambers and 64% for 160-ft square retorting chambers. With 20 feet thick walls, the cross section of the shale formation available for retorting would be 73% for 120-ft square retorting chambers and 79% for 160-ft square retorting chambers. Thus large retorting chambers and thin walls are necessary for the optimum recovery of oil shale resources (i.e., for the Occidental concept).

Assuming that 20% of the rock is mined-out to create the void volume necessary for subsequent rubblization, a 120 ft x 120 ft x 250 ft commercial size retort could yield 50,584 barrels of crude shale oil, at 65% retorting efficiency and for 15 gpt shale. The results from the Occidental experiments indicated a retort burn rate of 0.54 in/hr, thus the production period of a 250 ft high retort is 232 days and the production rate of crude shale oil from a commercial size retort is 218.5 barrels per day (BPD). Two hundred and twenty-nine retorts would be required to operate simultaneously to produce 50,000 BPD of crude shale oil if the average Fischer assay of the shale zone is 15 gallons per ton (gpt). For a shale zone with an average Fischer assay of 25 gpt, a minimum of 149 retorts would be required if the production goal of 50,000 BPD of crude shale oil were to be realized.

In the construction of the commercial size retort, Occidental plans mining at two levels. The upper mining level will be a complete heading at or near the top of the retort, and will serve as a base from which vertical longholes will be drilled for the loading of explosives. In the retorting process, combustion air will be supplied through the heading.

In the Occidental modified in situ process, retorting is initiated by heating the top of the rubblized shale column with the flame formed from compressed air and an external heat source, such as propane or natural gas. After several hours, the external heat source is removed and the compressed air flow is maintained, utilizing the carbonaceous residue in the retorted shale as fuel to sustain air combustion. In this vertical retorting process, the hot gases from the combustion zone move downwards to pyrolyze the kerogen in the shale below that zone, producing gases, water vapor, and shale oil mist which condense in the trenches at the bottom of the rubblized column (Figure 37). The oil production precedes the advancing combustion front by 30 to 40 ft. The crude shale oil and by-product water are collected in a sump and pumped to storage. The off-gas is composed of gases from shale pyrolysis, carbon dioxide and water vapor from the combustion of carbonaceous residue and carbon dioxide from the decomposition of inorganic carbonate (primarily dolomite and calcite). Part of this off-gas is recirculated to control the oxygen level in the incoming air and the retorting temperature. The off-gas has a heating value of approximately 65 Btu/scf. The part of the off-gas not recycled will be burned in a turbine for electric power generation after hydrogen sulfide removal by the Stretford process.

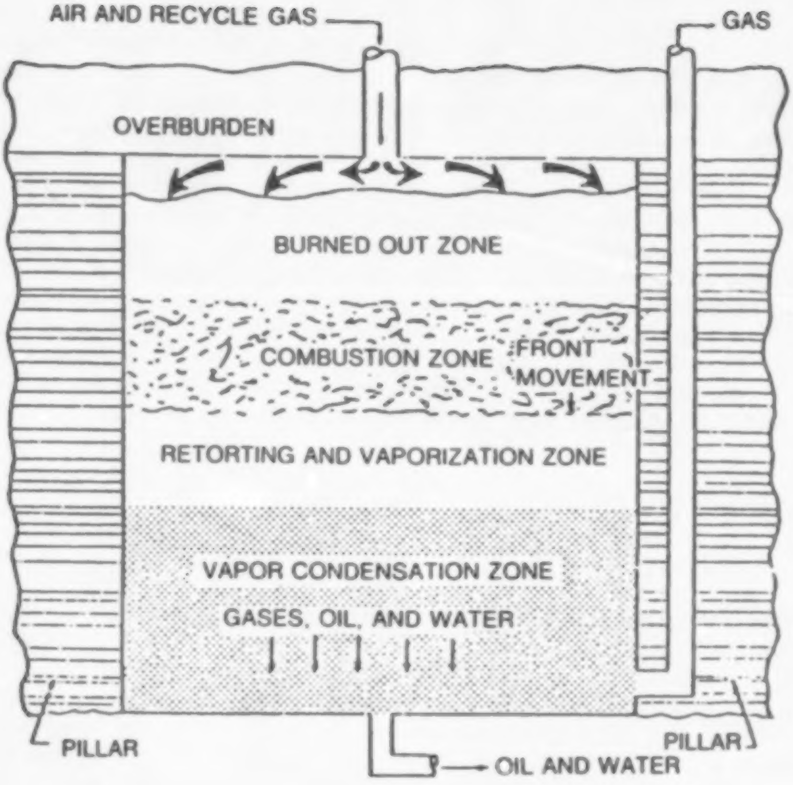
AIR AND RECYCLE GAS
GAS
OVERBURDEN
BURNED OUT ZONE
COMBUSTION ZONE
FRONT MOVEMENT
RETORTING AND VAPORIZATION ZONE
VAPOR CONDENSATION ZONE
GASES, OIL, AND WATER
PILLAR
PILLAR
OIL AND WATER

Figure 37

Flame Front Movement in the Occidental Modified In Situ Process

According to Occidental's estimate, only 20 to 25% of the electric power produced from the low-Btu gas is required for operating the modified in situ process. The minimum treatment required for the crude shale oil produced from the retorting process will include phase separation of the oil from the by-product water and the stabilization of the oil product. The wastewater effluent from the phase separator may be used for steam generation after appropriate treatment.

The crude shale oil produced from the Occidental process has a specific gravity of 0.904 (API gravity of 25°), a pour point of 70°F, a sulfur content of 0.71 weight percent and a nitrogen content of 1.50 weight percent. The crude shale oil is reportedly free of solids and may be used directly as boiler fuel.

Reference 8 contains an estimated energy balance for the retorting sections of an Occidental modified in situ plant. The provided energy balance covers both in situ and Lurgi surface retorting. The Lurgi retorts handle the approximate 20 percent of the oil shale removal from the modified in situ retorts before rubblization by explosives. In addition, a few additional percent of oil shale from development passageways will also be sent to the Lurgi retorts. The shale oil retorted both ways will be 25 gallons per ton average grade. Low-Btu gas produced by retorting will be used to generate steam and to produce electricity by gas turbine driven generators. An estimated heat balance based on reference 8 for both in situ and Lurgi retorting is given by Table 22. This can be represented diagrammatically by Figure 38. As indicated, Table 22 and Figure 38 cover the retorting sections of the plant only. The energy balance is for a plant producing 111,111 barrels of shale oil per stream day (BPSD). This results from 68,000 BPSD from in situ retorting and 32,000 BPSD from conventional (i.e., surface) retorting.

10.3 Applications

Current

Shale oil has been produced commercially for various periods of time in eleven countries since the initiation of shale oil operations in France in 1838. In Canada and the Eastern United States, a very small industry was operating in 1860 but disappeared when petroleum became plentiful. Currently, the only commercial production is in Russia (Estonia) and China with a combined production of approximately 150,000 barrels per day. All other shale industries (i.e., in other countries) succumbed because of the inability to compete with petroleum fuels. All production to date has generally occurred in retorts that would be considered of commercial size for U. S. operations (9).

Projected

The successful development and demonstration of a commercial scale shale oil production technology would provide a valuable alternative for the acquisition of liquid fuels. The ability to produce oil from oil shale would provide the potential means to produce liquid fuels from our vast shale oil resources and thereby reduce our dependence on imported and domestic petroleum products. The commercial scale development and future use of an oil shale technology are dependent on many factors. These include:

1) The demonstration on a commercial scale of a viable technology,
2) The ability to satisfy environmental concerns, and
3) The ability to produce a commercial product at an acceptable cost.

Table 22

Estimated Energy Balance for the Retorting Sections of an Occidental Modified In Situ Plant from 35 Gallons Per Ton Oil Shale (68,000 BPSD* In Situ and 32,000 BPSD Surface Retorted)

	10^9 Btu per hour			Percent of Total Energy Input
	MIS	Surface	Combined	
Product Output				
Product oil	16.91	7.82	24.73	51.94
Retort gas**	10.56	0.97	11.53	24.22
Recovered heat	--	0.44	0.44	0.92
System Losses				
Retorted shale	8.78	0.43	9.21	19.34
Flue gas	--	0.15	0.15	0.32
Miscellaneous losses	1.34	0.21	1.55	3.26
Energy Input	37.59	10.02	47.61	100.0
Raw shale	35.44	10.01	45.45	95.46
Steam	1.94	--	1.94	4.08
Electrical energy	0.21	0.01	0.22	0.46

* BPSD = barrels per stream day

** Low-Btu gas that can be used at site (e.g., to generate electricity)

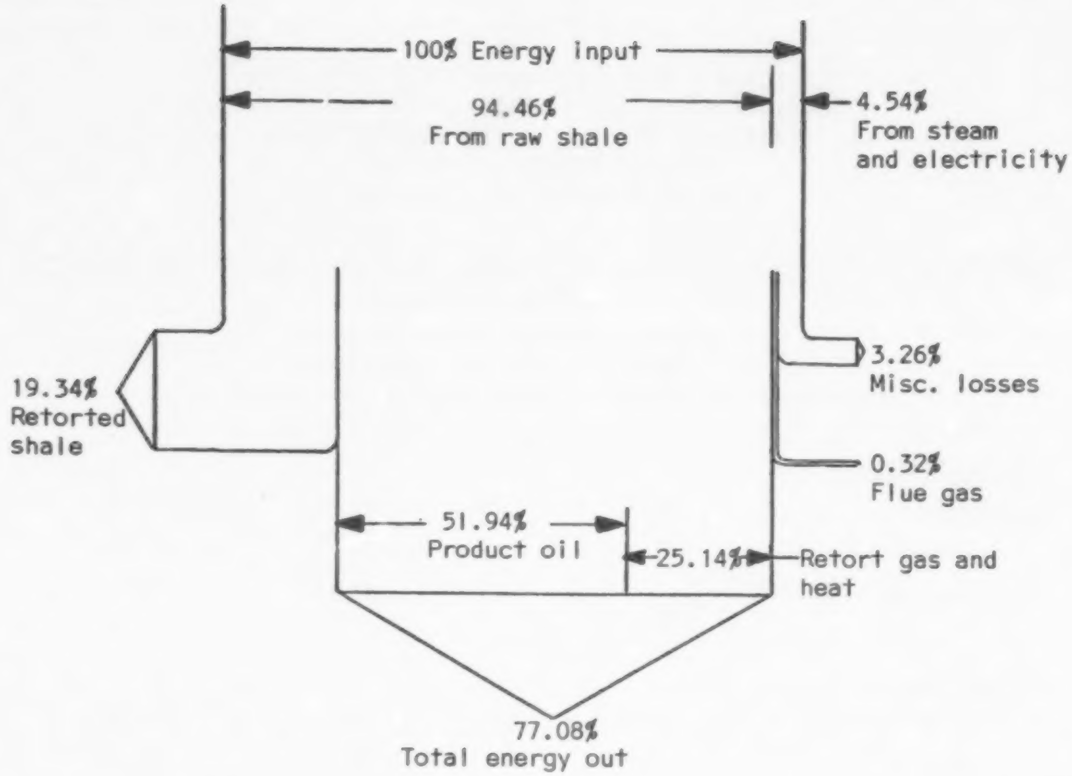
100% Energy input
94.46%
From raw shale
4.54%
From steam
and electricity
19.34%
Retorted
shale
3.26%
Misc. losses
0.32%
Flue gas
51.94%
Product oil
25.14%
Retort gas and
heat
77.08%
Total energy out

Figure 38

Estimated Energy Balance Schematic for the Retorting Sections of an Occidental Modified In Situ Plant

The most significant problems and uncertainties are associated with impacts on air and water quality, waste management, occupational health and safety aspects, and the cost to produce a marketable commodity.

10.4 Environmental Considerations

The Environmental Protection Agency, the Department of Energy, other governmental agencies, and other groups are studying environmental aspects of producing oil from shale. Currently, there remain a number of unanswered environmental questions. It may not be possible to provide a meaningful environmental determination until experience with one or possibly more operating plants is acquired. The technologies are just too new, the affected ecologies are not well understood, and the scale of operation is too massive to be able to predict (with a reasonable degree of confidence) the effect of an oil shale industry. In addition, envisioned environmental controls for the oil shale industry are subject to large uncertainties.

The most significant problems and uncertainties are associated with impacts on air and water quality, waste management, and occupational health and safety aspects.

Identified Pollutants (9)

Air Emissions

Atmospheric emissions can arise from several activities or operations during oil shale processing. The major source of SO_2, NO_x, and CO is fuel combustion for process heat; SO_2 is also emitted in the tail gases of sulfur recovery operations. The use of fuel oils in mobile equipment and in explosives will result in emissions of CO and NO_x. Hydrocarbons are present in both combustion emissions and in product storage tank vapors. Emissions of particulate matter can result from blasting, raw and spent shale handling and disposal, raw and spent shale dust in process gas stream, fuel combustion, and site activities which generate fugitive dust.

Emissions of potentially hazardous substances may occur during the extraction and processing of oil shale. Silica (quartz) may be present in dust derived from oil shale and associated rocks and in fugitive dust. Particulate emissions from fuel combustion and fugitive dust from spent shale handling and disposal can contain polycyclic organic material (POM) and certain trace metals. Gaseous ammonia, hydrogen sulfide, and volatile organics may be released during moisturizing and subsequent cooling of retorted shale. Catalyst materials may release particulate matters containing trace metals to the atmosphere during regeneration, handling, or final disposal.

Generally, the retorting operation itself does not involve atmospheric emissions; gaseous, liquid, and solid streams leaving the retort are handled by downstream systems before reaching an atmospheric interface. However, certain features inherent in the retorting method influence the nature and magnitude of emissions from other sources in the associated shale oil plant.

Sulfur in raw oil shale amounts to about 0.7 percent by weight, approximately one-third associated with the organic fraction; and two-thirds as pyrite (Fe_2S). During kerogen pyrolysis, about 40 percent of the organic sulfur in shale appears as H_2S in the produced gases, and the other 60 percent as heavier sulfur compounds in raw shale oil and in the spent shale carbonaceous residue. Pyritic shale sulfur does not decompose under nonoxidizing retorting conditions.

Actual SO_2 emissions associated with individual retorting processes will depend upon the degree of sulfur removal accomplished for in-plant fuels, the extent of on-site shale oil processing, and the degree of control applied to sulfur recovery tail gases. Combustion of any hydrocarbon fuel will produce oxides of nitrogen when air containing nitrogen is used as the source of oxygen. In addition, organic nitrogen contained in fuel can be partially oxidized to NO and NO_2.

The feed to a surface retorting plant always presents a particulate control problem. Run-of-mine raw shale commonly contains about five weight percent of ore of less than ½-inch size. A sizable percentage of this segment will become minus 100-micron particulate as a result of primary crushing.

Emissions of HCs and CO occur during incomplete combustion of fuels in process heaters and in mobile equipment. Hydrocarbons may also be vaporized during product storage. Equipment use and evaporative hydrocarbon emissions are not expected to be process specific.

The largest source of CO in an oil shale operation is mobile equipment used for mining and transport. The quantity of such emissions is a function of mining method and haul distances rather than retorting process.

The pyrolysis of essentially any type of organic material produces a certain amount of POM, and oil shale kerogen is no exception. Generally, POM compounds have a low volatility and will be associated with high boiling liquid or solid products of particulate matter. It should be noted, that although POM is known to be present in carbonaceous retorted shales, the biological availability and potential hazard of such material is not accurately known at present.

Release of POM to the atmosphere during oil shale processing can occur via three major pathways:

(1) Handling and disposal of retorted shale, fugitive particulates and possible volatilization of hydrocarbons;

(2) Combustion of shale derived oils containing POM; and

(3) Flue gases containing entrained retorted shale particulates, along with retort gas or spent shale coke combustion products.

Oil shale contains trace amounts of many elements. However, for elements other than Si, Fe, Al, Ca, Mg, Na, and K, the concentrations in oil shale are less than generally found in coal. In addition, conditions during retorting are not severe enough to volatilize most metallic and heavy elements. With notable exceptions such as arsenic (As) and possibly antimony (Sb), most trace elements (e.g., nickel (Ni), vanadium (V), molybdenum (Mo)) remain with the spent shale, or are found as components of raw and spent shale solids entrained in retort gases and in raw shale oil. Arsenic in raw shale apparently forms a range of volatile oil soluble compounds (perhaps organic arsines) during retorting, and appears in raw shale oil and all condensible oil fractions. If not removed during upgrading, arsenic will be present in shale oil combustion products.

Actual emissions of nonvolatile trace elements are anticipated in approximate proportion to raw and retorted shale particulate emissions for an oil shale extraction and retorting operation. Such emissions may not be different in nature or magnitude from those associated with the extraction and processing of other fuel and nonfuel minerals (coal, limestone, phosphate rock, etc.). Further, the dolomitic and/or alkaline nature of shale immobilized many elements as relatively inert oxide, carbonate, or silicate salts.

Metals (Ni, Co, Mo, Cr, Fe, Zn) and their compounds are used as catalysts for hydrotreating, de-arsenating, sulfur recovery, and trace sulfur removal. Emissions of particulate matters containing catalyst metals can occur either during on-site regeneration of during handling and disposal. Catalyst use is not unique to shale oil processing, and much information and experience in preventing hazardous emissions can be borrowed from the petroleum and related industries.

Solid and Liquid Effluents

The surface retorted shale from a modified in situ process can be a major problem. Surface retorted shale occupies a greater volume than the original shale and contains varying quantities of organic and inorganic residuals. The nature of these are dependent on many factors including process, site and climatic variables.

Aqueous wastes from oil shale processing can be broadly categorized as originating from direct or indirect sources. Direct sources are wastewaters generated from unit operations and/or processes, including wastewater from retorting operations; wastewater from upgrading operations; water from air emission control and gas cleaning systems; cooling water and boiler water blowdowns; water treatment systems; mine dewatering wastewater; and sanitary wastewaters. Indirect sources include: leachate from retorted shale disposal areas; run-off and erosion resulting from construction and site use activities; and run-off from mining and transport activities.

Water is a direct product of oil shale retorting, resulting from the release of free and inorganically bound water from raw shale, and combustion of organic material in shale. From 1 to 8 gallons of water are commonly produced per ton of input shale feed to a surface retort, depending on the retorting process and the composition of the shale processes. In situ process demonstrations have reportedly produced even greater amounts of water. Some water condenses with crude shale oil during separation of the oil from retort gases. This water can separate partially from crude shale oil during storage, or can appear in aqueous waste streams of shale oil upgrading operations. Water remaining in retort gases after oil separation can be condensed during cooling or gas cleaning operations, or can appear in the flue gas stream from retort gas combustion. Water separated from crude shale oil contains mainly ammonia, carbonate and bicarbonate, sodium, sulfate, chloride, and dissolved or suspended organic compounds (phenolics, amines, organic acids, hydrocarbons, mercaptans). Smaller quantities of calcium, magnesium sulfides, and trace elements may also be present, along with suspended shale fines. Water condensed from retort gases contains primarily ammonia and carbonates, with traces of organic substances and sulfur containing compounds. In particular, it should be noted that in situ and modified in situ retorting will result in various liquid, solid, and gaseous products being left in the retort zone. Their effect on aquifiers due to disruption and leaching is not known.

The quality of wastewater from an upgrading operation varies with the level of on-site upgrading or refining utilized. In general, a full-scale refining operation may include any of the following wastewater streams: oily cooling water, process water, and wash water.

Wastewaters are also collected during retort gas cleaning, tailgas cleanup, and foul water stripping. Major constituents in such waters are shale dust particulates, hydrocarbons, H_2S, NH_3, phenols, organic acids, and amines. Other constituents such as thiosulfate and thiocyanates may also be present.

Cooling water is used in retorting and oil upgrading to absorb heat which cannot be economically recovered for use in the complex or absorbed by air fan coolers. Cooling water is generally circulated through a wet cooling tower system to release this heat to the atmosphere. Because of evaporative losses, there is a constant buildup of dissolved solids which requires a portion of this recirculated water to be discharged as a blowdown from the cooling water system. Similarly, a fraction of the boiler water must be discharged as blowdown to minimize scaling of boilers. Both the cooling water and the boiler blowdown waters contain a high concentration of dissolved solids, and substances such as hexavalent chromium used for corrosion control.

Good quality water is needed to supply processing, cooling tower, steam generation, and other miscellaneous process uses. Wastes from water treatment systems generally consist of chemical sludges, backwash water from filtration system and blowdown from zeolite softening systems. The largest quantity of waste is lime sludge which is characterized by high hardness and dissolved salts content.

An appreciable amount of the water required for an oil shale plant is used for moisturizing of retorted shale. Much of this water requirement will be supplied by minewater and process wastewaters. Because of the large quantities of water utilized and the exposure of retorted shale to rain and snowfall, a source of indirect water pollution may occur via leaching or run-off from retorted shale piles.

Construction, mining, and site use activities may potentially result in increased sediment and dissolved solids loading in surface run-off and receiving streams. This indirect source of potential water pollution is not unique to oil shale extraction and processing but may require careful control due to the magnitude of site activities.

Regulatory Impacts

Each oil shale technology and resulting commercial implementation will have to be evaluated separately as to regulatory impacts. For example, the nitrogen content of the product shale oil will be higher than in coal or petroleum derived fuels and may result in unattractive NO_x levels upon combustion. Because of the differences in technologies and in state and local regulations, siting of a major oil shale facility must be addressed on a case-by-case basis.

The oil shale industry must comply with regulations and standards including requirements of the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Federal Nonnuclear Energy Research and Development Act, and the National Environmental Policy Act as well as applicable State laws. Failure to comply has the potential of halting all progress toward commercialization (10).

Undoubtedly, the oil shale industry will benefit from the experience of the petroleum industry in dealing with complex organic substances and new processes while complying with governing statutes.

10.5 Performance

Current

Even though an estimated heat balance (for a given process) and thereby an efficiency value is provided, it should be recognized that, currently, there are no commercial scale shale oil extraction and processing facilities in the United States. There have been some small scale experimental efforts and small scale demonstrations of some process elements (e.g., a specific retort). Therefore, there are no performance values that can be applied to a commercial scale plant.

Projected

It is difficult to provide confident estimates of operating efficiencies of future shale oil facilities. In this regard a given shale oil project could have various efficiency values depending on the specific definition. Efficiency values could be based on energy contained in resources in place or on the energy content of the shale into the retorting facility. In addition, efficiency values will depend on what system input and product output energy components are considered.

10.6 Economics

Current

There are no commercial scale oil shale processing facilities currently in operation in the United States.

Projected

The oil shale companies themselves are aware of the technological and economic uncertainties. One company recently stated that no one really knows what any of the available oil shale technologies will do or what they will cost in dollars per barrel until plants are built and operating and cost data collected (1). Even though there is considerable uncertainty, reference 11 does contain an assessment of economic and financial considerations.

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11. Direct Coal Liquefaction

11.1 Overview

Coal liquefaction is an emerging coal conversion alternative that holds promise for near-term commercialization allowing greater utilization of the nation's coal reserves. The liquid products that are produced vary with the type of process and the rank of the coal that is utilized.

Coal liquefaction processes can be classified into four types - direct hydrogenation, solvent extraction, pyrolysis, and indirect liquefaction. In direct hydrogenation, hydrogen is added catalytically to coal in a reactor under high pressure and temperature resulting in vapor and liquid phases which are cooled to separate the products, refined to remove by-products and, depending on the fuel product desired, further processed. In solvent extraction, a solvent is used as a hydrogen carrying agent to promote liquefaction under high temperature and pressure to produce the liquid fuels, after purification. In pyrolysis, crushed coal, thermally decomposed in the absence of oxygen, yields solids (char), liquids and gases. In indirect liquefaction, the coal is first gasified to make a synthesis gas and then passed over a catalyst to produce alcohols (methanol) or paraffinic hydrocarbons.

Direct hydrogenation, solvent extraction, and pyrolysis are classified as direct liquefaction processes. In the United States, some of the direct liquefaction processes receiving attention as having a potential for commercialization are H-Coal (direct hydrogenation), and Solvent Refined Coal and Donor Solvent (solvent extraction).

Research and development of coal liquefaction processes has been underway for many years. The first practical uses of coal-derived liquid fuels were about 1790 when the fuels were used for experimental lighting, heating, and cooking. During World War II, Germany produced liquid fuels from coal in industrial amounts via both direct and indirect liquefaction. Since then, coal liquefaction plants have been constructed in a number of countries but only one plant in Sasol, South Africa is still producing liquids from coal (via indirect liquefaction). Commercial demonstration of coal liquefaction has never been accomplished in the United States. Current U. S. activities are limited to research and development and pilot plant programs.

Environmental problems common to fossil energy facilities will also apply to coal liquefaction facilities. Liquefaction facilities do present some unique problems due to incomplete combustion resulting in a wide variety of organic compounds, reducing conditions resulting in H_2S and other reduced sulfur compounds and catalytic processes producing spent catalyst with associated environmental concerns. These problems are generally common to all liquefaction processes, however, since no large scale plants are in operation in the U. S., the only available data on emissions and effluents are estimates from pilot plant operations and cannot be quantified for a commercial operation.

Projected efficiencies for direct coal liquefaction facilities are in the 60 to 70 percent range. Exact values for coal conversion efficiencies are difficult to estimate and thus an exact value cannot be given until commercial demonstration takes place. In 1977, DOE estimated the cost to produce a synthetic crude to be \$4 - 6 per million Btu.

Although there remain unanswered questions relating to coal liquefaction (e.g., commercial demonstration, environmental impacts, costs), the successful development of a technology would provide a valuable energy alternative and allow greater utilization of our nation's coal reserves. Additionally, liquid fuels are easier to store, transport, and utilize than solid fuels, and during liquefaction, impurities (e.g., sulfur) can be removed. It appears that environmentally acceptable liquid fuels can be produced from our various ranks of coal.

11.2 Process Description

Concept

The basic objective of coal liquefaction is to convert coal to liquid fuels with minimal production of gases, liquids, and organic solid residues. All ranks of coal can be liquefied although some are more attractive than others. The liquid products vary both with the type of coal used and the particular process applied.

There are several methods for producing a liquid fuel from coal. As with gasification, either hydrogen has to be added or carbon removed from the compounds in the coal. In bituminous coal, for example, the carbon-to-hydrogen ratio by weight is about 16 to 1; in fuel oil the ratio is about 6 to 1. Although liquefaction is a complex process, it can be viewed as a change in the carbon-to-hydrogen ratio that can be accomplished by one of several reactions (e.g., pyrolysis) (1). The chemical structure of the coal influences the chemical reactions that will take place during the liquefaction process. The chemical structure of different coals show significant variance.

Detail

Coal liquefaction processes can be grouped into four distinct categories (2, 3):

- Direct hydrogenation (e.g., H-Coal)
- Solvent extraction (e.g., Solvent Refined Coal)

- Pyrolysis (e.g., Clean Coke)
- Indirect Liquefaction (e.g., Fischer-Tropsch)

In indirect hydrogenation, hydrogen is added catalytically to coal in a reactor under high pressure and temperature resulting in vapor and liquid phases which are cooled to separate the products, refined to remove by-products and, depending on the fuel product desired, further processed. The process conditions (temperature, pressure and amount of hydrogen added) determine the fuel produced. Processes and products in this category include:

- H-Coal produces boiler fuel or synthetic crude
- Synthoil produces synthetic crude or fuel oil

The solvent extraction process liquefies coal through indirect transfer of hydrogen to the coal using a process-derived solvent and a hydrogen atmosphere. Processes and products in this category include:

- Solvent Refined Coal produces boiler fuel or low sulfur solid fuel
- CO-Steam produces fuel oil
- Donor Solvent produces liquid and gas products

In pyrolysis, crushed coal, thermally decomposed in the absence of oxygen, yields solids (char), liquids and gases. These products, via the same process have been produced from coal for well over 100 years as the by-product of coking operations. Processes and products in this category include:

- Hydrocarbonization produces fuel oil
- Clean Coke produces coke and liquid fuels
- Flash Pyrolysis produces fuel oil, coke, and gas

Indirect liquefaction involves the initial gasification of coal to produce a mixture of CO and H_2 (synthesis gas), which is purified and converted to liquid fuels by reaction over appropriate catalysts to produce alcohols (methanol) or paraffinic hydrocarbons. A particular advantage of indirect liquefaction is that essentially all of the sulfur and nitrogen present in the coal can be separated in the gaseous phase and thus eliminated from the liquid products. These materials are difficult and expensive to remove to a very low concentration with direct processes. Processes and products in this category include:

- the Mobil produces gasoline

- Fischer-Tropsch produces liquid and gaseous fuels and chemical products

The Fischer-Tropsch process is significant in that it is the only large commercial coal liquefaction plant in operation. The plant is located in Sasol, South Africa.

In the United States, the direct liquefaction processes receiving DOE support that are closest to near-term commercial demonstration are H-Coal, Solvent Refined Coal, and Donor Solvent. Detailed descriptions summarized from DOE publications of these processes follow (4, 5, 6, 7).

H-Coal

The H-Coal pilot plant is located in Catlettsburg, Kentucky. This 600-ton of coal per day test facility recently commenced operation. The process is a catalytic hydroliquefaction process that converts high sulfur content coal to boiler fuels and to syncrude. A schematic of the process is provided in Figure 39. Coal is crushed to minus 60 mesh, dried, and then slurried with recycled oil and pumped to a pressure of about 200 atm. Compressed hydrogen is added to the slurry, and the mixture is preheated and charged continuously to the bottom of the ebullient-bed catalytic reactor. The upward passage of the internally recycled reaction mixture maintains the catalyst in a fluidized state. (Catalyst activity is maintained by the semi-continuous addition of fresh catalyst and the withdrawal of spent catalyst.) The temperature of the ebullient-bed catalytic reactor is controlled by adjusting the temperature of the reactants entering from the preheater. Typically, the temperature of the mixture entering the reactor is 650-700°F.

Vapor product leaving the top of the reactor is cooled to separate the heavier components as a liquid. Light hydrocarbons, ammonia, and hydrogen sulfide are absorbed from the gas stream and sent to a separator and a sulfur recovery unit. The remaining hydrogen-rich gas is recompressed and combined with the input slurry. The liquid from the condenser is fed to an atmospheric distillation unit. The liquid-solid product from the reactor, containing unconverted coal, ash, and oil, is fed into a flash separator. The material that boils off is passed to the atmospheric distillation unit that yields light and heavy distillate products. The bottoms product from the flash separator (solids and heavy oil) is further separated with a hydro-cyclone, a liquid-solid separator, and by vacuum distillation.

The gas and liquid products, composed of hydrocarbon gas, hydrogen sulfide, ammonia, light distillate, heavy distillate, and residual fuel, may be further refined as necessary. A portion of the heavy distillate

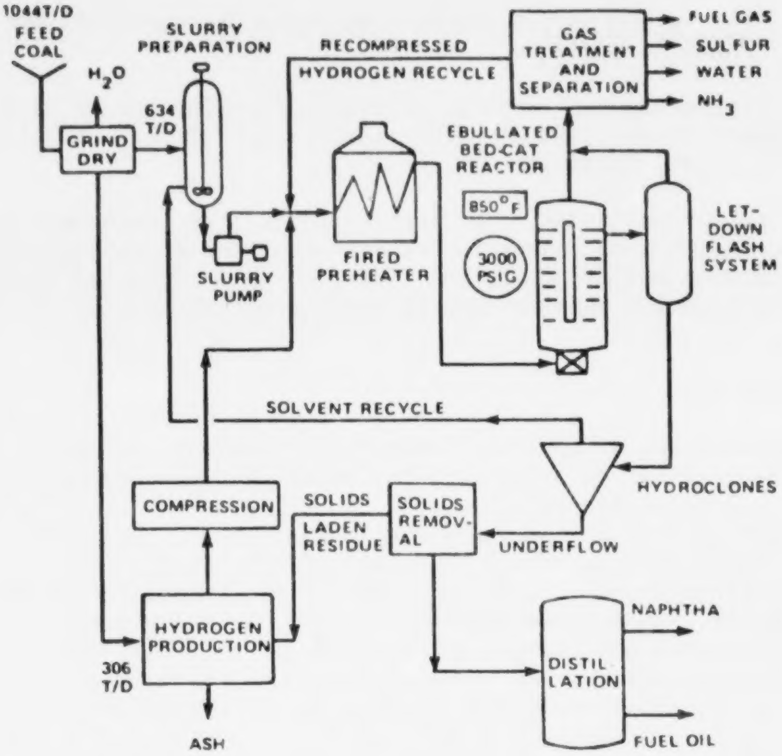
1044T/D
FEED
COAL
H$_2$O
SLURRY
PREPARATION
634
T/D
RECOMPRESSED
HYDROGEN RECYCLE
GAS
TREATMENT
AND
SEPARATION
FUEL GAS
SULFUR
WATER
NH$_3$
GRIND
DRY
EBULLATED
BED-CAT
REACTOR
850°F
3000
PSIG
FIRED
PREHEATER
SLURRY
PUMP
LET-
DOWN
FLASH
SYSTEM
SOLVENT RECYCLE
HYDROCLONES
COMPRESSION
SOLIDS
LADEN
RESIDUE
SOLIDS
REMOV-
AL
UNDERFLOW
HYDROGEN
PRODUCTION
306
T/D
ASH
NAPHTHA
DISTIL
LATION
FUEL OIL

Figure 39

H-Coal Process

is recycled as the slurry medium. The stream containing the unreacted carbon and some liquid will eventually be processed in a commercial installation to produce additional hydrogen needed for the process.

The specific operating conditions of the H-Coal process affect the type of fuel produced. For example, to produce synthetic crude, more hydrogen is required and there is a lower yield of residual fuel oil. In this mode, the separation of the solids (unconverted carbon and ash) from the liquid can be accomplished by vacuum distillation, and a special liquid-solid separation unit is not required. To produce clean fuel gas and low-sulfur residual oil as major products, the temperature and pressure in the ebullient-bed reactor are lowered, and less hydrogen is required.

Solvent Refined Coal (SRC)

The product from the original SRC mode (SRC-I) is a nearly ash-free low-sulfur solid fuel at ambient conditions. In a modification of the process (SRC-II) a distilled liquid product results. The SRC-I product is projected to serve as a clean fuel substitute for high sulfur coal. The SRC-II product can be used directly as a boiler fuel or, with further hydrogenation, as a refinery feed for conversion to conventional fuels. A 50-ton per day pilot plant is located at Fort Lewis, Washington. A demonstration plant for SRC-II (6000 tons of coal per day - 2000 barrels of oil per day) is currently planned to be constructed in Morgantown, West Virginia, with startup in 1984.

Figure 40 is a schematic of the SRC-I process. The coal is first pulverized and mixed with a coal-derived solvent in a slurry mix tank. The slurry is mixed with hydrogen, which is produced by other steps in the process, and is then pumped through a fired preheater and passed into a dissolver where about 90 percent of the moisture- and ash-free coal is dissolved. Several other reactions also occur in the dissolver: the coal is depolymerized and hydrogenated, which results in an overall dedrease in product molecular weight; the solvent is hydrocracked to form lower-molecular-weight hydrocarbons that range from light oil to methane; and much of the organic sulfur is removed by hydrogenation in the form of hydrogen sulfide.

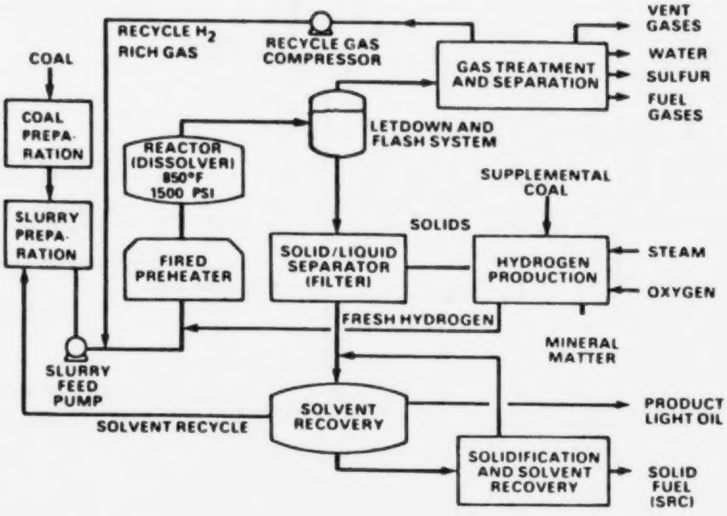
COAL
COAL PREPARATION
SLURRY PREPARATION
SLURRY FEED PUMP
SOLVENT RECYCLE
RECYCLE H_2 RICH GAS
RECYCLE GAS COMPRESSOR
REACTOR (DISSOLVER) 850°F 1500 PSI
FIRED PREHEATER
LETDOWN AND FLASH SYSTEM
GAS TREATMENT AND SEPARATION
VENT GASES
WATER
SULFUR
FUEL GASES
SUPPLEMENTAL COAL
SOLIDS
SOLID/LIQUID SEPARATOR (FILTER)
HYDROGEN PRODUCTION
STEAM
OXYGEN
FRESH HYDROGEN
MINERAL MATTER
SOLVENT RECOVERY
PRODUCT LIGHT OIL
SOLIDIFICATION AND SOLVENT RECOVERY
SOLID FUEL (SRC)

Figure 40

SRC-I Process

From the dissolver, the mixture passes to a separator where the gases are separated from the slurry of undissolved solids and coal solution. Raw gas is sent to a hydrogen recovery and gas desulfurization unit. Hydrogen recovered is recycled with the slurry coming from the slurry mix tank. Hydrocarbon gases are given off and hydrogen sulfide is converted to elemental sulfur.

The slurry of undissolved solids and the coal solution pass to a filtration unit where undissolved solids are separated from the coal solution. In the commercial-scale process, the solids are sent to a gasifier-converter where they react with supplemental coal, steam, and oxygen to produce hydrogen for use in the process. The coal solution passes to the solvent recovery unit and the final liquid product, solvent refined coal, is produced. The solvent-refined coal has a solidification point of 350° to 400° and a heating value of about 16,000 Btu/lb.

As previously indicated, modification of the SRC process (SRC-II) produces an all-distillate liquid instead of a solid residual fuel as the principal product. Figure 41 is a schematic of the SRC-II process. In

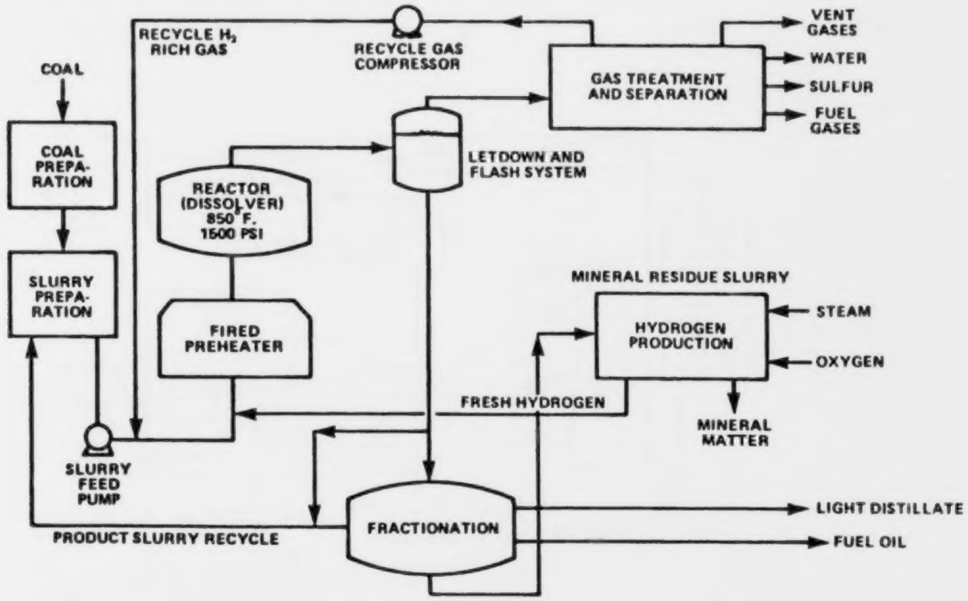
RECYCLE H_2 RICH GAS
RECYCLE GAS COMPRESSOR
VENT GASES
GAS TREATMENT AND SEPARATION
WATER
SULFUR
FUEL GASES
COAL
COAL PREPARATION
LETDOWN AND FLASH SYSTEM
REACTOR (DISSOLVER) 850° F. 1500 PSI
SLURRY PREPARATION
MINERAL RESIDUE SLURRY
HYDROGEN PRODUCTION
STEAM
OXYGEN
FIRED PREHEATER
FRESH HYDROGEN
MINERAL MATTER
SLURRY FEED PUMP
FRACTIONATION
LIGHT DISTILLATE
FUEL OIL
PRODUCT SLURRY RECYCLE

Figure 41

SRC-II Process

this modification, part of the product slurry is recycled as solvent for the pulverized coal feed instead of 450°F-plus boiling-range distillate. As a result of increased severity of reaction conditions, the hydrogen reaction is greater and a major part of the coal is converted to a liquid distillate product. The quantity of unconverted coal and vacuum residue is controlled so it is in balance with the requirements for gasifier feed to produce the process hydrogen requirements. This eliminates the solid/liquid separation step (filtration) required for production of fuel in solid form.

Donor Solvent

The chief features of the Exxon Donor Solvent (EDS) Process are illustrated in the process schematic, Figure 42. A pilot plant (250 tons of coal per day) is located in Baytown, Texas, next to an Exxon refinery. Crushed coal is liquefied in a non-catalytic reactor in the presence of molecular hydrogen and the hydrogen-donor solvent. The liquefaction reactor operates at 800-880°F and 1500-2000 pounds per square inch.

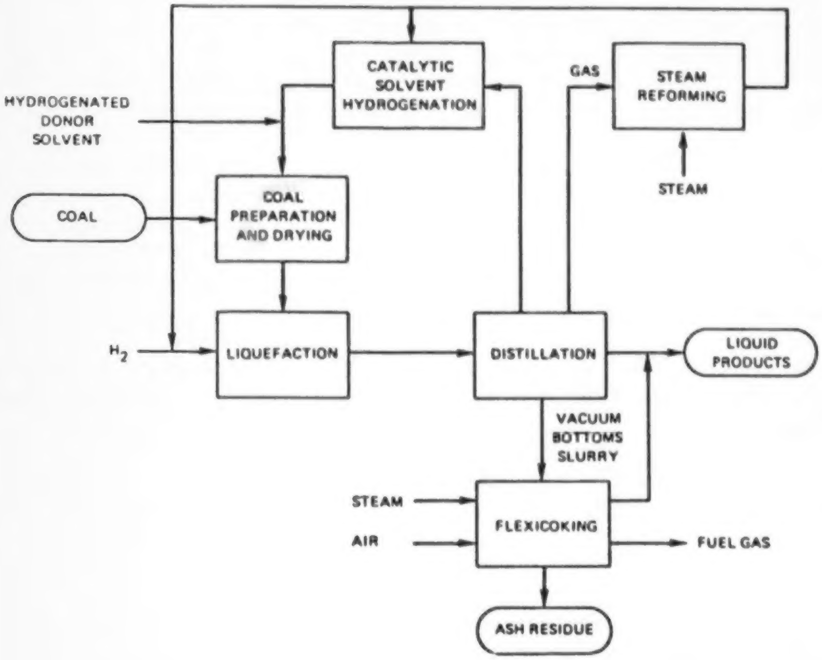
CATALYTIC SOLVENT HYDROGENATION
GAS
STEAM REFORMING
HYDROGENATED DONOR SOLVENT
STEAM
COAL
COAL PREPARATION AND DRYING
H_2
LIQUEFACTION
DISTILLATION
LIQUID PRODUCTS
VACUUM BOTTOMS SLURRY
STEAM
AIR
FLEXICOKING
FUEL GAS
ASH RESIDUE

Figure 42

Donor Solvent Liquefaction Process

The hydrogen-donor solvent is a 400°-850°F boiling range material. The solvent is a catalytically hydrogenated recycle stream fractionated from the middle boiling range of the liquid product. After hydrogenation, the solvent is mixed with fresh coal feed and pumped through a preheat furnace into the liquefaction reactor. Slurry leaving the liquefaction reactor is separated by distillation into gas, naptha, distillates, and a vacuum bottoms slurry. The vacuum slurry is coked to produce additional liquids.

The plant is "balanced" in that it is self-sufficient in both process fuel and hydrogen requirements. Process fuel and hydrogen are produced by gasifying the coke and by reforming C_1-C_2 gases from the liquefaction process.

The process is simple, and critical processing steps are adaptations of Exxon's base in petroleum refinery technology. Distinguishing features are the decoupled configuration of the liquefaction and catalytic hydrogenation sections and the use of vacuum distillation for solids/liquid separation. The catalyst does not contact coal minerals or high-boiling liquids, thereby leading to longer catalyst life at high activity. Use of hydrogenated rather than unhydrogenated recycle solvent produces a very significant improvement in process operability, particularly in down-stream processing vessels. Also, hydrogenated solvent produces higher distillate product yields than unhydrogenated solvent. The use of mechanical separation devices for solids/liquids separation is avoided.

The process gives high yields of low-sulfur liquids from bituminous or subbituminous coals or lignites. For Illinois bituminous coal, the liquid yield is 2.6 barrels of C_4+ liquid per ton of dry coal. Ammonia and elemental sulfur are the only by-products of significance. By varying liquefaction conditions or adjusting solvent properties, product distribution may be varied over a wide range.

An estimated heat balance as derived from reference 8 is given by Table 23. Diagrammatically, this is illustrated by the heat flow diagram, Figure 43.

11.3 Applications

Current

During World War II, Germany produced liquids from coal on a moderate scale. The conversion of coal to liquids has never been accomplished commercially in the United States. In the past, coal-to-oil plants were constructed in a number of countries. Currently there is only one plant in South Africa producing liquids from coal. This plant, SASOL I, employs an indirect liquefaction process.

Table 23

Estimated Heat Balance for a Commercial Scale EDS Plant

	Btu/day (10^6 Btu's)	Percent of Total Energy Input
System Products		
Liquids	323,071	61.72
Sulfur, ammonia	8,309	1.59
System Losses		
Ash, combustibles and sensible heat	26,882	5.13
Stack losses	20,039	3.83
Energy losses via water and air	136,853	26.14
Liquefaction and solvent hydrogenation (9.80%)		
Flexicoking (6.44%)		
Hydrogenation and recovery (6.72%)		
By-product recovery, offsites, and miscellaneous (3.18%)		
Other miscellaneous	8,309	1.59
Energy Input		
Coal (cleaned)*	488,761	93.37
Electrical power**	34,702	6.63

* Coal - Illinois No. 6; 10,574 Btu/lb as received prior to cleaning

** Power based on 8,500 Btu/kwh to generate

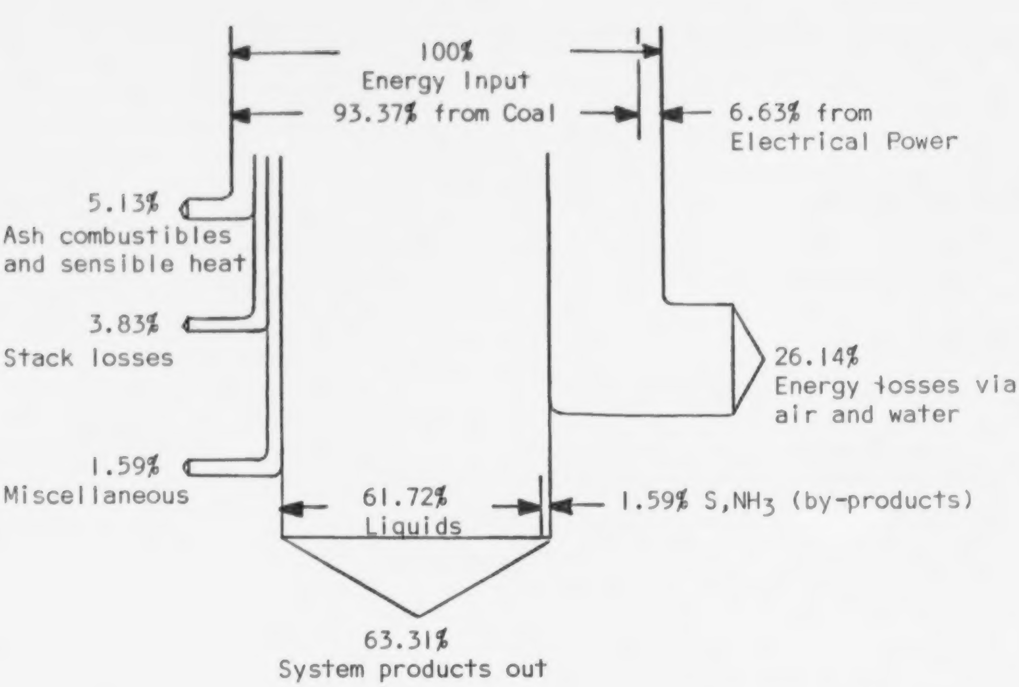
100%
Energy Input
93.37% from Coal
6.63% from
Electrical Power
5.13%
Ash combustibles
and sensible heat
3.83%
Stack losses
26.14%
Energy losses via
air and water
1.59%
Miscellaneous
61.72%
Liquids
1.59% S,NH$_3$ (by-products)
63.31%
System products out

Figure 43

Energy Flow Diagram for a Commercial Scale EDS Plant

Projected

The successful development and commercial demonstration of a coal liquefaction technology would provide a valuable energy alternative and would allow greater utilization of the nation's coal resources. There are many advantages to liquefying coal. Liquid fuels are generally more attractive than solid fuels in that they are easier to store, transport, and utilize. Also, during the liquefaction process, impurities found in coal (e.g., sulfur, metals, and ash) can be removed or their concentrations greatly reduced. Thus, it is possible to produce clean, environmentally acceptable liquid fuels from various ranks of coal. The development and future commercial use of coal liquefaction technology are dependent on many factors. Some of the more important include:

- The demonstration (large scale) of a viable technology,
- The ability to satisfy environmental concerns, and
- The ability to produce a commercially usable liquid fuel at an acceptable market price.

11.4 Environmental Considerations

Although many of the environmental issues associated with conventional fossil fuel utilization are common to coal conversion processes, liquefaction technology presents some unique problems (2). These include: the identification of materials with carcinogenic, mutagenic, and related effects; characterization and treatment of wastes, fugitive emissions, and effluents; and disposal of sludges and solid wastes. These problems are generally common to all liquefaction technologies; however, particular processes may have to be evaluated individually. Liquefaction does have the inherent advantage of separating the processing of the coal from the ultimate utilization. Since impurities can be removed from the coal during liquefaction, a "clean" fuel can be delivered to the utilization site (possibly an urban area) and thus the power generation facility will not have to cope with the impurities. A major environmental consideration in direct coal liquefaction is product toxicity due to the presence of high molecular weight organic compounds.

Identified Pollutants

Air Emissions

Development and commercialization of a coal liquefaction industry creates a concern with regard to the introduction of air pollutants into the atmospheric environment (2). The typical materials produced in a coal liquefaction facility which could have a detrimental impact on air quality include: hydrogen sulfide, ammonia, particulate matter (e.g., coal dust and process fines), hydrocarbons, sulfur dioxide, hydrogen cyanide, and small amounts of nitrogen dioxide, polycyclic hydrocarbons, and heavy metals. These emissions result from such activities as fuel combustion, coal preparation, sulfur recovery, ammonia storage, petroleum storage and miscellaneous hydrocarbon losses.

The major air emissions from liquefaction facilities are generally known and conventional control techniques may be applicable. The Dravo Corporation, in a 1976 handbook produced for the U. S. government, provides information on a number of industrial sulfur removal systems (Handbook of Gasifiers and Gas Treatment Systems, FE-1772-11, February 1976). The majority of the proprietary systems described are for removing H_2S from industrial gases. Some systems in addition to removing H_2S also remove other gaseous effluents (e.g., CO_2, NH_2, HCN). Almost all of the addressed systems have been in existence for many years with significant industrial usage. Such systems include the Selexol and the Stretford processes that have been used for selectively cleaning up gaseous impurities from processes used to convert oil or coal to other fuel form(s). Liquefaction air emission streams may contain impurities which could reduce the capabilities of commercially available control technologies.

However, in some instances, advanced controls may have to be developed before such plants are constructed on a commercial scale. In addition, airborne pollutants will be transported into the general environment and possibly transformed into other compounds after emission from coal liquefaction facilities. Conventional models are generally adequate to predict atmospheric dispersion for a high stack and flat land scenario. However, more detailed atmospheric transformation and dispersion information will be required to fully utilize these models.

The 1977 Clean Air Act amendments mandate that fossil energy facilities, including coal conversion plants, utilize the "best available technology" to control pollutants. Coal liquefaction (and other process facilities) constructed in nonattainment areas will be subject to emission trade-off policies. The energy and cost penalties of applicable air pollution controls must be characterized as well as the secondary pollutants which may be emitted by the controls.

Liquid Effluents

Coal liquefaction processes may produce waste effluents which have broad temperature and pH ranges and may contain a variety of materials such as: suspended particles, ammonia, toxic trace metals, phenols, aromatic hydrocarbons, thiophenes, aromatic amines, and other organic compounds (2). Conventional control and wastewater treatment techniques possibly could be applied to some of these materials. However, particularly troublesome areas requiring more study include: phenols, trace metals and the final disposal of the effluents (2).

Water quality may also be affected by gaseous streams, fugitive effluents and air emissions which may settle or be washed into water bodies by rain. Improper handling or disposal of solid wastes may also release dissolved and suspended solids and organics. Control and treatment options compatible with water discharge standards should be identified and their effects evaluated. Ultimate discharges (after treatment) can generally be projected for each coal liquefaction process. The general effects of these discharges at specific locations on indigenous aquatic organisms and communities can also be predicted.

Effluent constituents may accumulate and/or be transformed in the water column and biotic sediment or aquatic ecosystems. Current methods for predicting the movement of waste contaminants through surface and groundwater systems must be evaluated for locations where liquefaction facilities may be located.

Solid Waste

Solid wastes generated by coal liquefaction processes consist primarily of ash and refuse removed from the coal and sludges and solids recovered from waste treatment processes. The major solid waste streams, as well as minor ones such as spent catalyst, must be characterized and appropriate disposal techniques determined. Where appropriate, new treatment and disposal techniques may need to be developed.

Conventional disposal of solid wastes (especially ash) in offsite landfills will require transport and handling equipment and relatively large areas of land. The handling, transportation and disposal of wastes must be controlled to prevent fugitive dust emissions and accidental discharges. Groundwater leaching is another concern which must be evaluated if landfills are used as disposal areas for coal liquefaction wastes. Physical and chemical reactions involved, effects of various methods of disposal upon leachability, effective control and contrainment techniques, and compliance with new State hazardous waste disposal regulations should all be evaluated.

A DOE publication has estimated that the total solid wastes to be disposed of by a large-scale facility would be about 1200 to 2800 tons per day for a coal liquefaction plant, and 1000 to 2500 tons per day for an SRC-I plant (2). Most of these wastes will be in the form of ash. Disposal of these wastes would cover approximately 300 to 700 acres to a depth of 10 feet over a 20-year period. Approximately 250 to 525 acres would be needed to dispose of wastes from an SRC plant.

Regulatory Impacts

Each liquefaction technology will have to be evaluated separately as to regulatory impacts. Because of the difference in technologies and also varying state and local regulations, siting of a major coal liquefaction facility must be approached on a case-by-case basis.

A coal conversion industry must comply with regulations and standards including requirements of the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Federal Nonnuclear Energy Research and Development Act, and the National Environmental Policy Act as well as applicable State laws. Failure to comply has the potential of halting all progress toward commercialization.

Current standards for hazardous air pollutants limit mercury, beryllium, and lead emissions. These standards conceivably could put a limit on coal types than can be utilized in future demonstration plants. Since effluent guidelines have not been developed for most fossil energy technologies, permit requirements are determined on a case-by-case basis by States or by EPA (2).

Disposal of specific materials used in coal liquefaction may be regulated in the future. Currently, solid waste disposal must comply with stringent standards. Monitoring is required and State or EPA permits for all landfills will be required by April 1, 1988.

The Resource Conservation and Recovery Act of 1976 (RCRA) has guidelines for the land disposal of solid wastes (40 CFR 241). These standards set minimum levels of performance for any solid waste land disposal site. Additional standards have been proposed for disposal of solid wastes that contain hazardous pollutants. All future coal liquefaction facilities may have to abide by these solid waste standards (9).

Undoubtedly, a coal conversion industry would benefit from the experience of the petroleum industry in dealing with complex organic substances and new processes while complying with governing statutes.

11.5 Performance

Current

Currently, there are no coal liquefaction facilities operating in the United States. Therefore, all projections are based on technology still in the development stage. Reference 10 indicates an estimated efficiency range of 60-70 percent for direct liquefaction processes.

Projected

It is difficult to provide realistic and confident estimates for coal conversion efficiencies. Also, efficiencies reported often do not indicate whether the value is for a plant that purchases all, part, or none of the supplemental energy needed in the conversion. (These purchases include electricity, steam, and other utilities.)

Reference 10 indicates an efficiency range of 60-70 percent for Direct Hydrogenation (H-Coal). Reference 1 stated overall energy efficiencies for various coal liquefaction processes to be in the 62 to 69 percent range. This is consistent with the provided estimated heat balance based on reference 8. Limiting factors that can reduce efficiencies significantly are specific to each process and output mix and must be separately computed.

11.6 Economics

Current

Since there are no coal liquefaction processes currently in operation in the United States, the economics must be projected.

Projected

As with all complicated and unproved energy technologies, the cost to produce a million Btu is, at best, an estimate. The estimated cost by DOE to produce a synthetic refined crude oil as of mid-1977 was $4 - 6 per million Btu (11). Undoubtedly, the actual cost will be high. In general, the estimated cost from a direct liquefaction process is less than for indirect liquefaction.

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12. Fuel Cell

12.1 Overview

The fuel cell, by converting chemical energy directly to electricity, can efficiently use fuels without a mechanical intermediate step. Fuel cell power plants offer many attractive characteristics such as modular construction, low environmental emissions, high efficiency and rapid response to load-demand fluctuations. Because of their modular construction, fuel cells are easily transported and installation times and costs reduced.

The fuel cell concept itself is not new: such cells have already provided power for moon landings and, between 1971 and 1973, provided electric power to 50 apartment houses, commercial establishments, and small industrial buildings. What is new is an effort to capitalize on the fuel cell's inherent flexibility, safety, and efficiency by putting together a generator system that can use a variety of fuels to economically meet today's utility-scale power needs.

A fuel cell is a sandwich consisting of an anode, electrolyte, and cathode, much like a battery. Hydrogen-rich fuel is fed down the anode side of the cell, where the hydrogen loses its electrons, leaving the anode with a negative charge. Air is fed down the cathode side, where its oxygen picks up electrons, leaving the cathode with a positive charge. The excess electrons at the anode flow towards the cathode, creating electric power. Meanwhile, hydrogen ions produced at the anode (when electrons are lost) and oxygen ions from the cathode migrate together in the electrolyte. When these ions combine, they form water, which leaves the cell as steam because of the heat of the electrochemical process.

The inclusion of fuel cell power plants in utility systems conceivably would yield a number of benefits. Reduced resource consumption would result from high full-load and part-load efficiency. Because of their modular construction they could be installed at substations on transmission and distribution systems if constant fuel supply is available (1). This modularity could mean lower cost, shorter plant construction lead time, and greater flexibility in plant size. Fuel cell systems have been identified as candidates for power generation in a variety of utility applications. These are:

- Upgrading old urban plants by using existing sites more efficiently with decreased environmental impact.

- Supplying new generating capacity where environmental considerations restrict combustion plants (especially when transmission right-of-way is limited and plants must be sited close to population areas).

- Complementing existing power systems' peak load capacity, where quick response and part-power efficiency are required.

- Supplying power for small and medium sized municipal and rural utilities under 100 MW, a range in which other power plant types cannot operate as efficiently.

Low water requirements, limited emissions, and quiet operation help make fuel cell plants an attractive power option. An advanced fuel cell plant would produce less waste heat than a comparable capacity conventional or nuclear plant and thereby require less cooling. Because fuel cell plants can use a variety of hydrocarbon fuels, they share with conventional generating processes the environmental problems currently associated with extracting and processing fossil fuels. However, since the fuel cell portion of the plant does not involve a combustion process, emissions from overall operations are significantly lower than emissions from conventional power plants. The fact that fuel cell plants operate with very little noise also helps to make them attractive for a number of use situations.

Projected electricity generating efficiencies for hydrogen fuel cells are estimated between 54 and 61 percent. The Energy Conversion Alternatives Study (ECAS) team estimated an overall efficiency of 50 percent for their conceptual molten carbonate fuel cell power plant containing an advanced coal gasifier.

Although still in conceptual and prototype stages, fuel cell plants offer the potential to produce electricity efficently on both small and large scales. These systems could be used to complement existing facilities or supply new generating capacity where environmental considerations restrict conventional combustion plants.

12.2 Process Description

Concept

The fuel cell (Figure 44) is a device that produces electrical energy from the controlled electrochemical oxidation of fuels (2). The basic components of a simple hydrogen-oxygen fuel cell are the electrodes (anode and cathode) and the electrolyte, which can be either acidic or basic. The reactants are normally consumed only when the external circuit is completed, allowing electrons to flow and the electrochemical reaction to occur. When the external circuit is completed, an oxidation reaction, yielding electrons, takes place at the anode and a reduction reaction, requiring electrons, occurs at the cathode. The electrodes provide electrochemical-reaction sites and also act as conductors for electron flow to the external circuit.

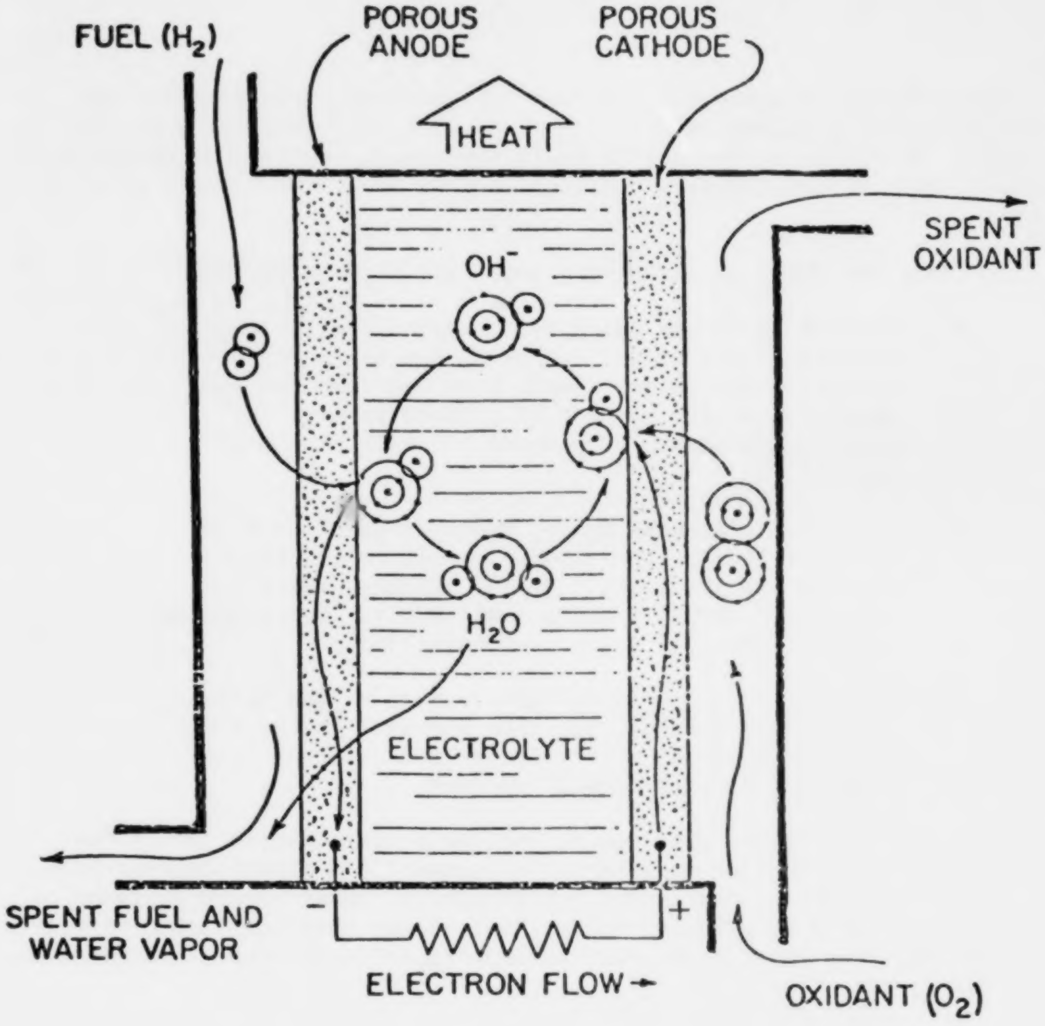
FUEL (H_2)
POROUS ANODE
POROUS CATHODE
HEAT
SPENT OXIDANT
OH^-
H_2O
ELECTROLYTE
SPENT FUEL AND WATER VAPOR
−
+
ELECTRON FLOW →
OXIDANT (O_2)

Figure 44

Typical Fuel Cell

Fuel cells make efficient use of fuels by converting chemical energy directly to electricity and heat without going through a mechanical intermediate step.

The basic components of a fuel cell are the inlets to the anode and cathode, the electrodes, and an electrolyte. The individual cells can be aligned in series to build up voltage. When the external circuit is closed, the electrochemical reaction initiates electron flow and the reactants are consumed resulting in good fuel efficiency even at low loads. By utilizing the cell's waste heat (e.g., in the reforming reaction), overall efficiencies above 75 percent are theoretically possible (3).

There are three basic designs under active consideration:

- In acid cells employing acid electrolyte, hydrogen ionizes at the anode, releasing two electrons per molecule, and oxygen reacts with hydrogen ion and electrons at the cathode to produce water. The electron release at the anode provides an electric current.
- In molten carbonate cells, hydrogen combines with carbonate ion at the anode to yield water, carbon dioxide and electrons. At the cathode, meanwhile, oxygen and carbon dioxide combine with the returning electrons to regenerate carbonate ions.
- In solid oxide cells, oxygen ionizes at the cathode, consuming electrons, and then migrates to the anode, where it combines with hydrogen and releases the electrons for the flow of current.

A fuel cell power plant would include a fuel conditioner, a fuel cell power section, and an inverter to convert the direct current (d.c.) fuel cell output to alternating current (a.c.) power. Several types of fuel cells could be used in the fuel cell power section. Table 24 presents the types which have received significant attention for aerospace, military, and utility use (4).

Detail

A fuel cell power plant generates electricity from naturally occurring fuels (e.g., petroleum products, natural gas, coal), or synthetic fuels (e.g., hydrogen, synthesis gas). The power plant has three major subsystems: the fuel conditioner, the fuel cell power section, and the inverter. The typical configuration is shown in Figure 45 (5).

The fuel conditioner generates a hydrogen-rich gas for use in the fuel cell power section. With light distillates, natural gas or methyl fuel, the fuel conditioner is a catalytic steam reformer of the type used in the petrochemical industry. Heavier liquid fuels can be conditioned in partial oxidizers or in advanced fuel processors presently being investigated. Coal must be processed in a coal gasifier of the same type as proposed for use with combined-cycle power plants.

Table 24

Comparison of Fuel-Cell Types

Cell Type	Operating Temperature	Typical Electrodes	Typical Electrolyte	Typical Structural Materials	System Considerations
Aqueous Acid	80-205°C Gas Diffusion	Teflon bonded acid in matrix	Phosphoric acid	Bonded graphite	Waste heat used for steam production
Molten Carbonate	650-760°C	Sintered nickel oxide & cobalt	Alkali metal carbonates in a fiber reinforced particle matrix	Stainless steel	Requires addition of CO_2 to air supply; waste heat used to reform process heat
Solid Oxide	815-1095°C	Metallic and semiconductor firms	Doped metal Oxides	Ceramic	Highest temperature for integration with fuel conditioner

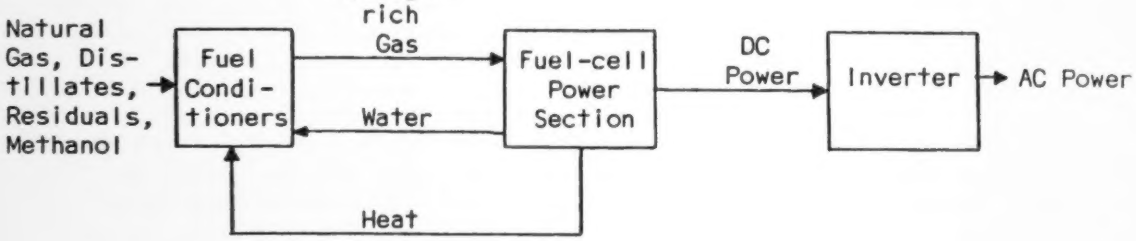
Natural Gas, Distillates, Residuals, Methanol
Fuel Conditioners
Hydrogen-rich Gas
Water
Heat
Fuel-cell Power Section
DC Power
Inverter
AC Power

Figure 45

Fuel Cell Power Plant

The fuel cell power section is composed of single cells having three basic components: a fuel electrode (anode), an air electrode (cathode), and an electrolyte to form an ion conductor between them. The process in the cell is the reverse of the well-known process of water electrolysis in which electricity is passed through water to produce hydrogen and oxygen. A fuel cell combines the hydrogen from the processed fuel with the oxygen from the air to produce water and d-c electricity. Aside from some waste heat, the only by-products are water and carbon dioxide. No pollution is generated by the electrochemical reaction.

A single cell generates approximately one volt of d-c power. In a fuel cell power section, stacks of such cells are connected in series to permit generation of hundreds to thousands of volts. At present technology levels, a single fuel cell generates roughly 100 to 200 watts of electricity for each square foot of electrode area. Connecting a number of assemblies in parallel permits power levels from kilowatts to megawatts.

The third subsystem of the fuel cell power plant, the inverter, converts the d-c electrical output of the fuel cell power plant to a-c electricity. Inverters are presently used in applications ranging from small consumer devices to large-scale electric utility equipment. The development of inverters for fuel cell power plants has been directed toward technological improvements that reduce unit cost and improve efficiency.

In the Energy Conversion Alternatives Study (ECAS) (4) conceptual design power plant, coal is gasified in an air blown, ash agglomerating, fluidized-bed gasifier operating at 200 psia. Sulfur is removed from the product gas in iron oxide beds. The clean gas is fed to molten carbonate fuel cells that operate at 150 psia and a nominal temperature of 650°C. Direct current power from the fuel cells is converted to alternating current in solid-state inverters. Fuel cell exhaust gases drive turbocompressors that pressurize the fuel cells and gasifiers. Waste heat from the fuel cell and the gasifier is used to drive a steam turbine bottoming cycle. Bottoming cycle throttle conditions were 2400 psig and 540°C with single reheat to 540°C. Bottoming cycle heat is rejected in wet forced-draft cooling towers. The gasifier vessels, fuel cell modules, inverters, and turbocompressors are designed for factory fabrication with rail transport to the plant site. This resulted in a rating of 108 MW for the gasifier and fuel cell islands. The steam turbine bottoming cycle rating of 203 MW was selected to provide reasonable economies of scale for the steam plant. Four gasifier and fuel cell islands are required to provide sufficient waste heat for the steam turbine; consequently, total net output from the plant is 635 MW. Two-thirds of the plant output is furnished by the fuel cells, with the remainder being from the steam plant.

Reference 4 contains thermal emission data for the conceptual fuel cell power plant described above. Based on reference 4, an estimated heat balance for a 500 MWe fuel cell power plant was developed (Table 25). Diagrammatically, this can be represented by Figure 46. The provided values are for fuel cell power plant with a steam turbine bottoming cycle. If a gas turbine bottoming cycle were to be utilized, the overall efficiency would drop to 45 percent because the gas turbine bottoming cycle can not utilize fuel cell waste heat as effectively.

Table 25

Heat Balance for 500 MWe Fuel Cell Power Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Electrical Energy Output	1706.5	49.9
Losses		
Cooling tower heat reject	866.0	25.3
Stack heat losses	437.5	12.8
Miscellaneous heat losses	412.5	12.0
Total Energy Input	3422.5	100.0

12.3 Applications

Current

Presently, there are only experimental/feasibility fuel cell power plant related activities in this country. The outcome of these efforts and such unsolved questions as fuel acceptability, reliability, and costs will contribute to defining the proper application of this technology.

Projected

While features of fuel cell power plants appear attractive for central station applications, the low pollution potential of the fuel cell and its effectiveness at small sizes also suggest that fuel cell power plants be used where the characteristics of conventional power plants would prohibit their use (4). For example, when the generating facility is located close to or at the load, the amount of energy lost in transmission is reduced, and the need for additional transmission investment

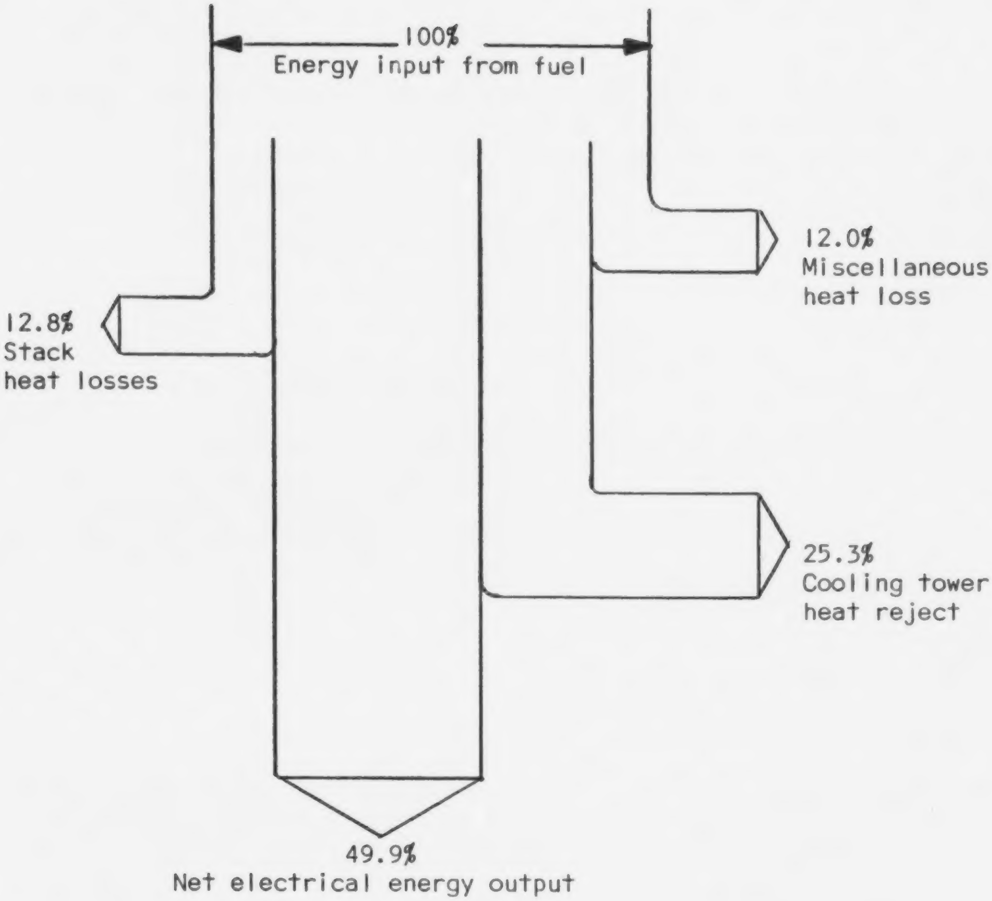
100%
Energy input from fuel
12.0%
Miscellaneous heat loss
12.8%
Stack heat losses
25.3%
Cooling tower heat reject
49.9%
Net electrical energy output

Figure 46

Heat Flow Diagram for Fuel Cell Power Plant

is deferred. In addition, the waste heat from a fuel cell plant can be recovered and used. Thus, a fuel cell power plant can offer significant economic advantages in certain situations.

The fuel cell may provide an alternative method for meeting new load requirements in congested urban or suburban areas having restrictive pollution standards and limitations on new transmission rights-of-way. Use of the fuel cell to feed power into an electric utility's distribution system at points near the load to be served would eliminate the energy losses (approximately 3 to 6 percent) in transmitting power from a remote central plant to the substation and afford the opportunity to recapture waste heat (4).

The fuel cell also offers a more fuel-efficient approach to supplying a utility system's spinning reserve requirements. Spinning reserve refers to power plants kept on line either at idle or part power to permit rapid system repsonse to demand changes and to provide continuity of service in the event of a plant outage. In this type of operation, low part-power heat rate and fast response to load change are important generator features. Combining conventional units at rated load with fuel cell units at part load could prove to be an efficient, economic mix. The use of fuel cells to provide spinning reserve capacity could permit up to 15 percent reduction in overall utility system fossil fuel consumption (4).

Pratt & Whitney has a major program for dispersed generation using natural gas reformers and low-temperature (<250°F) fuel cells of the phosphoric acid and potassium hydroxide electrolyte types. The Institute of Gas Technology has been doing complementary work using low-temperature phosphoric acid and high-temperature (2200°F) molten carbonate electrolyte cells.

In the Pratt & Whitney system, the cells operate at about 230°F. This system burns the effluent from the fuel cells to provide heat to reform hydrocarbons, such as natural gas, yielding a hydrogen/carbon dioxide mixture. (Heat produced in the cells is also used to preheat the water used in the reforming reaction.) Given proper pretreatment, hydrogen can be used directly in the cells as can the fuel gas from coal gasification. Thermal and electrical output from nuclear reactors can be used to produce hydrogen and oxygen via the electrolysis of water. In this manner, fuel cells have the potential to become an integral part of electrical systems for the dispersion of electrical power. However, if is not known at this time if this approach is being seriously investigated.

Testing on a 4.8 MWe demonstration fuel cell power plant at Consolidated Edison (New York City) should begin in 1980. This electric utility fuel cell utilizes a phosphoric-acid electrolyte and generates approximately two thirds of a volt d-c per cell. This effort was undertaken to demonstrate not only technological feasibility, but also the social acceptability of locating a power plant in a densely populated area (3, 6).

United Technology Corporation is currently working on the development of second generation fuel cell models employing molten carbonate electrolyte. Advantages of this system are a reduction in the by-product heat rate and operation at high temperature such that a catalyst is not required in the electrodes. Argonne National Laboratories and General Electric Company also are conducting ongoing research into molten carbonate systems.

A third approach to fuel cell development has been initiated by Westinghouse Electric Company. This system employs a high temperature cell with a solid oxide electrolyte. Westinghouse feels this type of fuel cell could be employed in central power generation plants.

In 1976, DOE sponsored a study to examine industrial applications of fuel cells. Twelve major industries were selected on the basis of intensity of energy use, availability of waste gases to fuel the cells, type of power consumed (i.e., a-c or d-c), and compatibility with cogeneration of heat. The best matchings were in the rubber, styrene, and ethylene industries where the utilization of waste heat from the cells could reach 100 percent. A chlorine plant was shown to be only capable of utilizing 30 percent of the waste heat but, nevertheless, is an attractive candidate because it consumes d-c power and produces hydrogen fuel (3). In the spring of 1978, DOE requested proposals for a feasibility study for the construction, installation, and operation of a 4.8 MW fuel cell power plant in industrial cogeneration applications similar to the utility trial already in progress but this time involving industry.

However, acceptable these feasibility studies prove to be, the widespread use of fuel cells is presently limited by high equipment costs and the narrow range of acceptable primary fuels (currently natural gas or naphtha)(3).

12.4 Environmental Considerations

Identified Pollutants

Central station systems using fuel cells will produce the same chemical pollutants as those created by conventional utilization of the same fuels (2). That is, a fuel cell power plant which utilizes coal for its natural fuel will require coal preparation facilities similar to conventional coal fired steam plants. For example, there may be dust nuisance from wind action on the pile and leaks and spills during handling operations.

The proposed commercialization concept for the phosphoric acid fuel cell anticipates using natural gas or naphtha as fuels. This type of operation is not expected to create a major environmental concern. However, future development anticipates utilizing a coal derived gas or high hydrogen industrial waste gas as a fuel and this operation may create environmental worker health and safety concerns inherent in coal gasification and by-product handling operations.

The fuel cell, however, is particularly sensitive to conventional combustion pollutants, primarily sulfur (2). This sensitivity will require extensive fuel pretreatment to eliminate contaminants prior to electrochemical oxidation. For an equivalent electrical power output, the higher operating efficiency of an advanced fuel cell system will result in reductions in the quantity of fuel required and effluents along with a reduction in the emission of nitrogen oxides due to reduced temperatures to which the air streams are exposed. Waste heat rejection is not a significant problem with fuel cell power systems since much of the waste heat is used in the fuel gasification or reforming process. The excess heat is rejected to the atmosphere, and cooling water may not be required.

An environmental study performed by Exxon for the EPA estimated emissions from a 638 MWe molten carbonate fuel cell power plant (7). The NO_x level in the stack gas was estimated at 0.013 μg/J (0.03 lb/MBtu). This level apparently reflects the low temperature of combustion in the fuel cell catalytic burner. However, NO_x levels may prove higher than the thermal NO_x values reported, due to combustion of ammonia and other nitrogen compounds present in the coal gasifier product (7).

Hydrocarbon emissions in stack gas were estimated to be negligibly small. Similarly, particulate emissions in the stack gas should be at a very low level, since the fuel cell electrolyte system serves to trap whatever solids appear in the effluent gases. The sulfur level in fuel cell exhaust was estimated to be about 0.086 μg/J (0.2 lb/MBtu), due to thermodynamic limitation on the efficiency of the iron oxide desulfurization process (7).

For a coal fueled fuel cell power plant, there will also be solid and liquid effluents from the coal storage piles and handling area. Rain runoff will contain suspended solids and may also contain soluble sulfur and iron compounds.

The production of leachate from the fuel cells and sludge disposal from the electrolysis process offer the potential for water pollution. However, with established technology, these waste streams can be effectively treated and the pollution controlled.

Until commercialization of fuel cell power plants is realized and the fuel(s) for the plant known, it is difficult to identify specific pollutants associated with the operation. The experimental/feasibility activities thus far, have not indicated any unique environmental problems.

Regulatory Impacts

Since large scale commercialization for fuel cell power plants will probably not take place until after 1990, the regulatory impacts are unknown. Estimates of emissions from naphtha-phosphoric acid systems are under current NSPS standards for fossil fueled power plants (8).

12.5 Performance

Current

Since there are no full scale fuel cell power plants currently operating, no performance efficiencies can be given.

Projected

The fuel cell has the potential for high fuel efficiency over a full operating range from minimum to maximum power. The theoretical maximum efficiency of the fuel cell is a function of the fuel and oxidant used. These theoretical cell efficiencies range between 80 and 100 percent. Gross efficiency is the product of the theoretical maximum efficiency and the ratio of the operating voltage to the theoretical voltage. For hydrogen fuel cells, this efficiency is estimated between 54 to 61 percent (2).

The ECAS conceptual design of an integrated coal gasifier and molten carbonate fuel cell power plant estimates the overall efficiency to be 50 percent. The high efficiency of the fuel cell prime cycle, the availability of high-temperature waste heat for the steam turbine bottoming cycle, and the availability of high-pressure, high-temperature fuel cell exhaust for driving turbocompressors combine to provide this relatively high overall efficiency. An alternate design utilizing a gas turbine bottoming cycle has an estimated efficiency of 45 percent (4, 5).

12.6 Economics

Current

Since there are no large fuel cell power systems presently operating, a current figure for the costs per kilowatt hour is unavailable. Costs have been calculated for a coal fueled, high temperature system. However, unresolved problems in any of the fuel cell processing steps could require significant process additions and add significantly to capital costs and thus the cost of energy.

The major cost items relating to the fuel cell are the cell itself, power converters and the spare parts. The key item is the cost of the fuel cell.

Projected

Costs have been projected for a coal-fueled, high-temperature system by considering research and development progress to date and comparing unit costs of various elements with similar items in a coal fired steam turbine power plant (2). By assuming that the cost of electricity produced by a coal-fueled fuel cell system is equal to that from a steam turbine system, the allowable capital costs for the fuel cell system can be projected. The result of these assumptions and calculations is to suggest that a coal-fueled fuel cell system can produce competitively priced electricity if it can be built for a total capital cost of $294 to $374 per kilowatt electrical (2). As previously indicated, the three critical items are the fuel cell, power inverter and spare parts. Each of these has projected cost ranges that will allow reaching the cost target.

An essential factor is the cost of the fuel cells. The cost range allocated, $60 to $80 per kilowatt electrical, corresponds to a manufactured cost of $7.00 to $9.30 per pound based on the materials requirements. Total material costs for these thin-film, solid-electrolyte fuel cell assemblies have been estimated to be about $21 per kilowatt electrical ($2.45 per pound), leaving an allowable margin for manufacturing and assembly of $39 to $59 per kilowatt electrical ($4.55 to $6.85 per pound). These allowable manufacturing costs show reasonably good agreement with independent direct estimates (4).

The National Academy of Sciences (NAS) estimated the total installed cost for a 635 MWe integrated coal gasifier fuel cell power plant to be $595 million or $937/kW, as indicated in Table 26 (4). The power plant cost is based on an estimated five-year lead time. A high degree of factory fabrication and low coal handling, gasification, and heat rejection requirements associated with the high power plant efficiency help minimize the cost of this power plant.

Table 26

1975 Capital Cost Estimate Summary for Integrated Coal Gasifier Fuel Cell Power Plant (635-MW Plant)

Item	$ Millions
Land, improvements and structures	48
Coal handling, gasification, gas cleanup, and ash handling	79
Fuel cell system equipment	94
Steam plant bottoming cycle equipment	50
Electrical plant equipment	51
A&E services and contingency	78
Escalation and interest during construction (at 48.7%)	195
TOTAL	595

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13. Magnetohydrodynamics (MHD)

13.1 Overview

Magnetohydrodynamics (MHD) is a potential energy alternative in which electricity is generated directly from thermal energy, thus eliminating the conversion step of thermal to mechanical energy encountered in conventional steam electric generators. However, due to the nature of the process, it would be inefficient to apply MHD by itself to the large scale generation of electricity. Therefore, its eventual implementation is being planned around combining MHD with a conventional steam plant to make use of the waste heat from the MHD generator. The efficiency of such a combined MHD/steam plant is predicted to be about 50 percent or greater (1), as compared to 32 to 35 percent for conventional coal-fired power plants with flue gas desulfurization (FGD) systems. Much of this increase in efficiency is attributed to the fact that, unlike the case of rotating machines, all the rigid structures in MHD generators are stationary, thus permitting operation at elevated temperatures approaching 5000°F. These temperatures are much higher than even the most advanced contemporary plants, resulting in much higher efficiencies throughout the entire thermal cycle than are attainable in conventional plants (2).

There are three types of MHD systems: open-cycle, closed-cycle plasma, and closed-cycle liquid metal. In all of these sytems, an electrically conductive fluid (either gaseous or liquid) is passed through a magnetic field, thereby inducing a voltage drop across the gas stream. Electrodes convey the electricity to an inverter where the direct current naturally produced by the system is transformed to alternating current, which can be transmitted directly into an electric power grid. Of the three major types being considered, a combined open-cycle MHD/steam generator system offers the greatest potential to improve electricity generation plant efficiency and cost performance.

Initial development of MHD began during the late 1950's. Programs exist both in this country and abroad, notably in Japan and the U.S.S.R. The basic distinction between the United States and foreign programs is the emphasis abroad on "clean" fuels usage; that is, natural gas in the U.S.S.R. and fuel oils in Japan. In the United States, emphasis is on coal as the primary fuel. The abundance of domestic coal and its ability to be used directly in an environmentally acceptable manner, make it an attractive candidate fuel for MHD power generation (1).

MHD could be commercially available in the late twentieth century. The Department of Energy (DOE) has the lead in MHD development in the U.S., but other government agencies such as the Environmental Protection Agency, the National Science Foundation, the National Aeronautics and Space Administration, and the Office of Naval Research, as well as the Electric Power Research Institute in the private sector, also fund research on various aspects of MHD development and impacts.

Although much work remains before the widespread application of the magnetohydrodynamic energy conversion process to electric utility power generation, there is experimental evidence that MHD can significantly improve overall power plant efficiencies. Another promising aspect of this rapidly developing technology is the ability to remove, during the process, pollutants such as SO_x, NO_x, and particulates generated in the combustion of coal, thereby eliminating the need for external flue gas scrubbing to meet environmental standards (3).

13.2 Process Description

Concept

MHD is an application of a simple law of physics that has been practiced for over 150 years to generate electricity. This law states that a conductor moving across a magnetic field produces an electrical current. In the case of MHD, electricity is generated by the interaction of a conductive fluid moving through a magnetic field. Such an application is not new. MHD began to evolve over a century ago, but now the attempt to translate it into a viable, commercially acceptable energy-conversion technology is intensifying (2).

The principle of MHD can best be explained by examining the simplest type of MHD generator, named after the English physicist Michael Faraday, depicted in Figure 47. As shown in Figure 47, the basic MHD generator consists of a channel, suspended in a magnetic field, consisting of a cathode, anode, and insulating walls. The flow of the conducting fluid ($\underline{u}$) across the magnetic field ($\underline{B}$) results in an induced electromotive

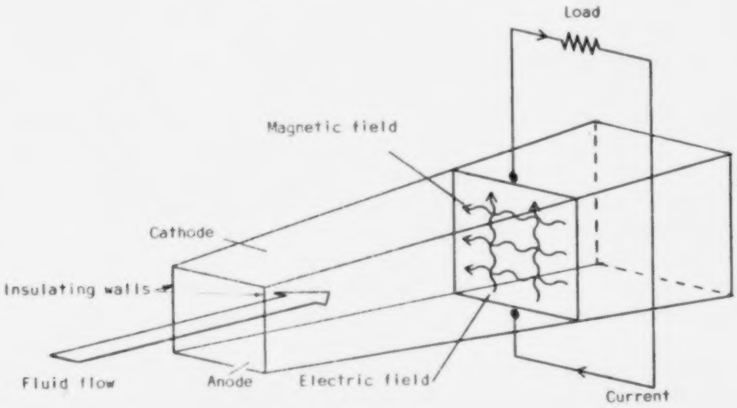

Figure 47

Faraday MHD Generator

force (EMF) and a current in an external load. This particular generator configuration can operate efficiently only when the fluid is a liquid metal as opposed to a conductive gas. However, other generator configurations and power takeoff schemes have and are continuing to be developed which permit the use of the more practical gaseous conductive fluid.

As would be expected from the discussion above, the key element in the systems now under development is the MHD generator. Essentially, this is an expansion engine that converts super-hot gases from the burning coal directly into electricity. In order to accomplish this, the coal is first pulverized and then burned in a highly efficient combustor. A small amount of an alkali metal salt (usually potassium carbonate) is added to the combustion gases to produce a plasma. This super-hot swarming mass of electrically charged gas then passes at high velocity through a strong magnetic field between two electrodes. The positive and negative ions separate and collect at opposing electrodes. The difference in potential between the electrode plates drives a current through an external circuit.

The heart of the MHD generator is the channel which is suspended between the poles of a powerful magnet. This is comprised of a multitude of hollow rectangular metal frames stacked horizontally and insulated from each other to form a long corridor through which the hot gases flow. Electrodes are mounted on opposite sides of each frame through which water circulates to prevent overheating.

By seeding the combustion gas with easily ionized materials such as potassium or cesium, the electrical conductivity sufficient for the process can be obtained at somewhat lower temperatures (4500° to $5000^{\circ}F$) than would be required otherwise. From an economic as well as environmental standpoint, potassium--in the form of potassium carbonate (K_2CO_3) or potassium hydroxide (KOH)--is the preferred seed material for open-cycle MHD. The potassium seed not only enhances the conductivity of the combustion gas, but also provides a unique built-in capability for removing sulfur products released during the combustion of sulfur-bearing fuels (in particular, high-sulfur coal). The potassium seed reacts preferentially with the sulfur at high temperatures and later precipitates out as potassium sulfate (K_2SO_4) when the combustion gas cools. The potassium sulfate can be removed from the system along with the ash by particulate control devices and then be regenerated to yield potassium carbonate or potassium hydroxide, which is recycled (1).

Detail

Much of the early work with MHD was performed with liquid and gaseous fuels. As stated earlier, MHD developmental programs in both Japan and Russia are designed for gas and oil firing. Although there is some limited research in closed-cycle systems, the high temperatures achieved in open-cycle operation with resultant improvements in efficiency and their applicability to coal utilization favor this latter type (3).

Open-Cycle MHD

A simplified schematic of a complete open-cycle MHD/steam plant is presented in Figure 48. This possible configuration is representative of the types of integrated designs being developed. It should be noted that it is presently conceptual, and testing of such a system has yet to be accomplished (4). In the system outlined in Figure 48, coal is dried and crushed before being fed to the combustor. The water-cooled combustor operating with preheated air produces combustion gas products at temperatures in excess of 4600°F. Eighty-five percent of the coal slag is rejected from the combustor. The combustion gas is seeded with potassium carbonate (K_2CO_3) to increase its electrical conductivity. This product is then expanded in an MHD generator producing a d-c electrical output. The expanded gases are reduced in velocity in a diffuser section to recover the remaining kinetic energy before entering the first heat exchange state--the radiant furnace--at temperatures in excess of 3660°F. A two-second residence time is provided in this furnace at approximately 2900°F to permit decomposition of NO_x as an emission control step. Combustion is completed by the addition of air at the exit of this heat exchange section. The gases then enter a series of regenerative high-temperature air pre-heaters. These cyclic, refractory heat exchangers are utilized to preheat the combustion air to 2500°F. The exhaust gas then enters a secondary furnace containing a steam generator and low-temperature air preheater section (the combustion air exits from this heat exchanger at approximately 1400°F). The combustion gas then enters an economizer section where its temperature is reduced to approximately 250°F before passing through an electrostatic precipitator and discharged out the stack. The seed material, K_2CO_3, is used to increase the electrical conductivity of the gas as well as to tie up the sulfur in the coal as potassium sulfate (K_2SO_4) (5). Experimental tests have achieved better than a 99 percent removal of the SO_2 from the effluent gas (6). This potassium sulfate is collected from the heat exchange components and the electrostatic precipitator and returned to a seed recovery system where an intermediate-Btu gas reduces the K_2SO_4 to K_2CO_3 seed material and hydrogen sulfide (H_2S). Elemental sulfur is recovered from the H_2S in an integral Claus plant. Feedwater is used to cool the combustor and MHD channel/diffuser. Steam is generated at 3500 psi/1000°F/1000°F in the heat exchange equipment. This steam is utilized in two steam turbines: one provides mechanical drive to the air compressor which supplies air at approximately 10 atmospheres for the combustor/MHD channel. The other steam turbine drives an a-c generator. The d-c output of the MHD channel is converted to a-c in solid-state inverters (5).

Closed-Cycle MHD

In the closed-cycle MHD processes, the basic energy conversion process is the same as that for open-cycle MHD (i.e. motional electromagnetic induction). However, in the closed-cycle processes, the working

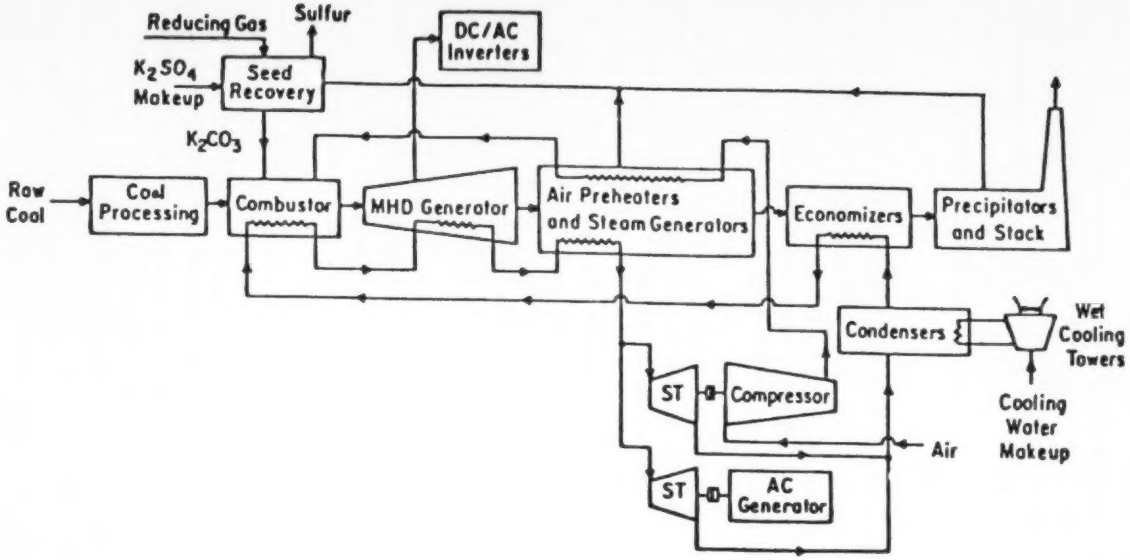
Reducing Gas
Sulfur
DC/AC Inverters
K_2SO_4 Makeup
Seed Recovery
K_2CO_3
Raw Coal
Coal Processing
Combustor
MHD Generator
Air Preheaters and Steam Generators
Economizers
Precipitators and Stack
Condensers
Wet Cooling Towers
Cooling Water Makeup
ST
Compressor
Air
ST
AC Generator

Figure 48

Open-Cycle MHD/Steam Plant - Schematic of Possible Configuration fluid is in a closed-loop system and receives the heat energy indirectly from a primary source through a heat exchanger. The primary heat source can be from the combustion of coal, other fossil fuels, or from a nuclear reactor. Because the working fluid is recycled in closed-cycle systems, there is more latitude available in choosing the working fluid and in obtaining electron densities that give sufficient conductivity. As a result, somewhat lower temperatures than those required in open-cycle systems are necessary to obtain sufficient conductivity for the MHD process. The extraction of thermal energy from the working fluid and its conversion to electricity in an MHD channel and conventional steam-bottoming plant are similar for open- and closed-cycle systems. There are two major approaches to closed-cycle MHD technology: plasma systems and liquid metal systems (1).

In a closed-cycle plasma MHD system, the working fluid is a noble gas, such as argon, which is seeded with an easily ionized material such as cesium. Figure 49 is a schematic diagram of a closed-cycle plasma MHD system (7). Air is preheated prior to entering the combustor. The hot combustion gas is ducted to heat exchangers which transfer heat to the argon working fluid. After leaving the heat exchangers, the combustion gas passes through an air preheater prior to being exhausted out the stack. The argon gas is expanded through a nozzle where it is seeded with cesium. The argon/cesium gas passes through the MHD generator which, as in open-cycle MHD, produces d-c power. After passing through a diffuser, the gas flows through an unfired steam generator. The cesium is condensed into liquid in the precooler, purified, and then reinjected at the nozzle. The argon is compressed, purified, and recycled to the high-temperature heat exchanger. The steam turbine plant produces substantial electric power and drives the argon compressor (1).

Liquid metal systems are very similar to closed-cycle plasma systems, with one major exception: a gas-liquid metal froth is used as the working fluid rather than a noble gas. Liquid metal systems have high electrical conductivities compared to totally gaseous systems, the potential for lower temperatures, and the applicability of lower magnetic fields. As a result, a smaller plant and higher extraction efficiencies may be possible. Figure 50 is a schematic diagram of a liquid metal MHD system (7). The pressurized liquid metal (usually sodium) is heated to peak cycle temperature in an externally heated exchanger fired by a fluidized-bed coal combustor and then flows to a mixer where heated helium is injected as a uniform dispersion of bubbles. Heat is transferred from the liquid to the gas, resulting in nearly isothermal expansion as the fluid passes through the MHD generator. After leaving the generator, the gas and liquid are separated and the liquid is recirculated back to the mixer. The gas passes through the diffuser to a steam bottoming plant where its heat is utilized. The helium then is compressed and recycled to the heat exchanger and the mixer (1).

As previously indicated, the emphasis in the United States is on the combined open-cycle MHD/steam generator system approach. Since all

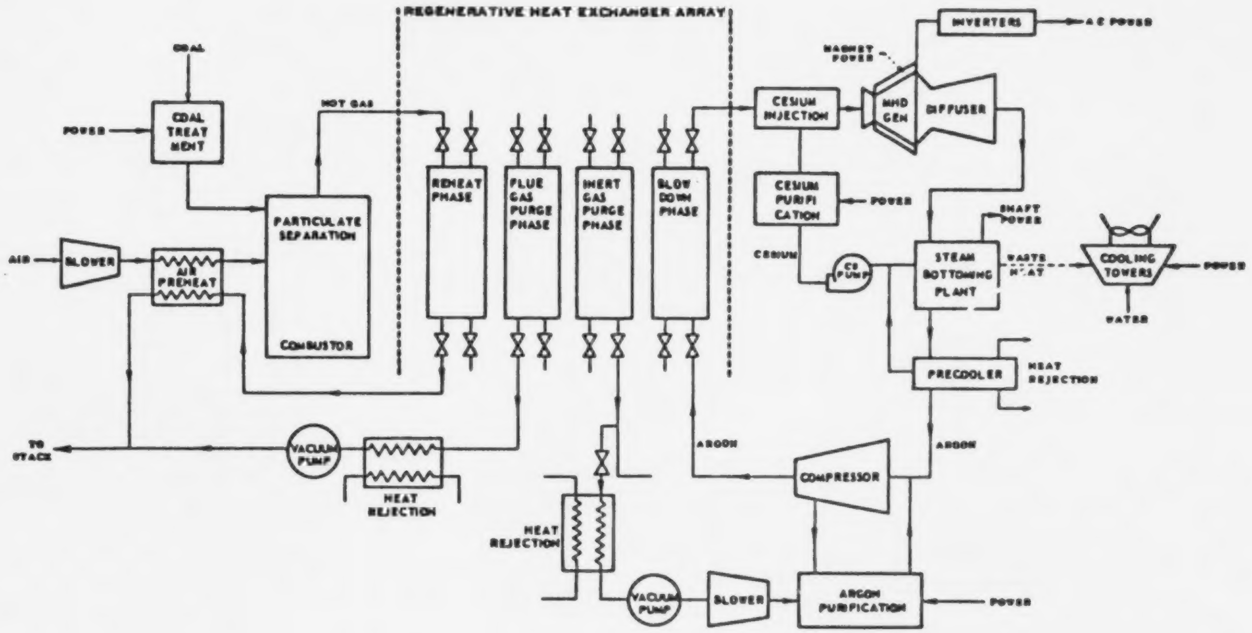
REGENERATIVE HEAT EXCHANGER ARRAY
COAL
POWER
COAL TREATMENT
HOT GAS
AIR
BLOWER
AIR PREHEAT
PARTICULATE SEPARATION
COMBUSTOR
REHEAT PHASE
FLUE GAS PURGE PHASE
INERT GAS PURGE PHASE
BLOW DOWN PHASE
CESIUM INJECTION
CESIUM PURIFICATION
POWER
CESIUM
CS PUMP
MAGNET POWER
MHD GEN
DIFFUSER
INVERTERS
A C POWER
SHAFT POWER
STEAM BOTTOMING PLANT
WASTE HEAT
COOLING TOWERS
POWER
WATER
PRECOOLER
HEAT REJECTION
ARGON
ARGON
COMPRESSOR
TO STACK
VACUUM PUMP
HEAT REJECTION
HEAT REJECTION
VACUUM PUMP
BLOWER
ARGON PURIFICATION
POWER

Figure 49

Simplified Schematic of Closed-Cycle Inert Gas MHD Topping Cycle

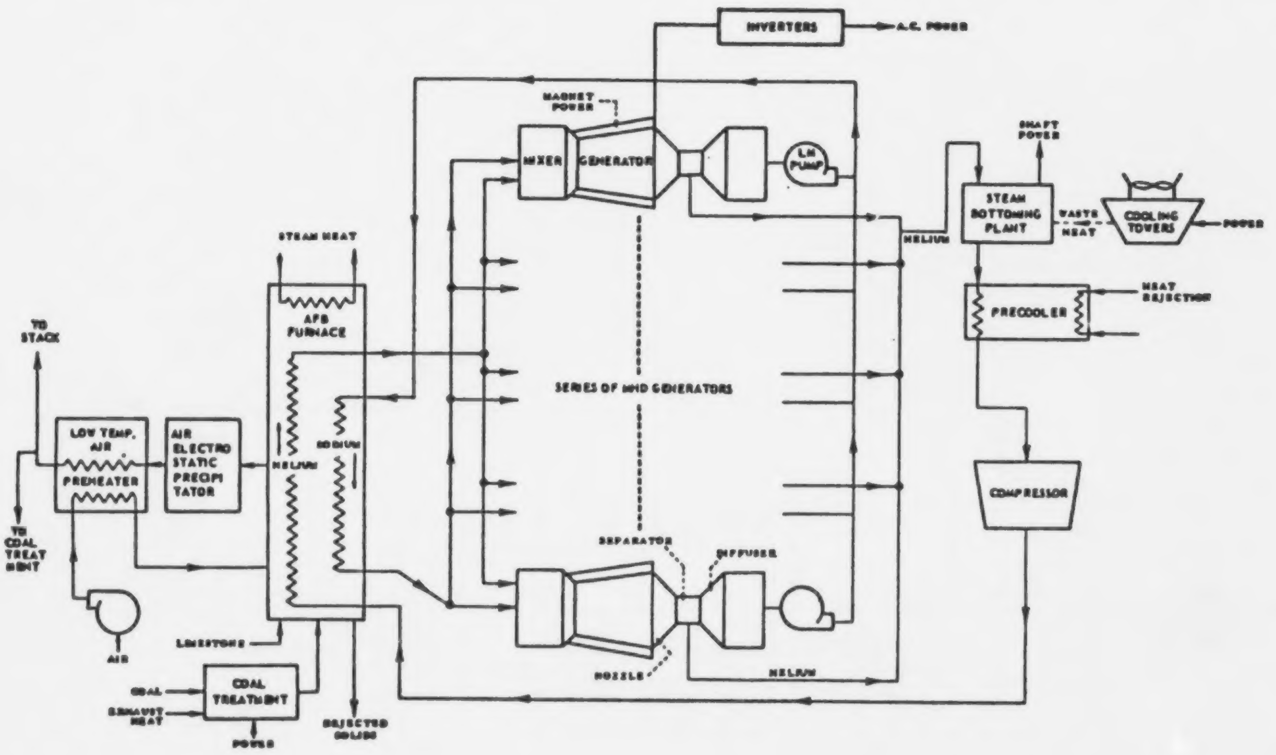
INVERTERS
A.C. POWER
MAGNET POWER
MIXER
GENERATOR
LM PUMP
SHAFT POWER
STEAM BOTTOMING PLANT
WASTE HEAT
COOLING TOWERS
POWER
HELIUM
PRECOOLER
HEAT REJECTION
STEAM HEAT
AFB FURNACE
TO STACK
LOW TEMP. AIR PREHEATER
AIR ELECTRO STATIC PRECIPITATOR
HELIUM
SODIUM
SERIES OF MHD GENERATORS
COMPRESSOR
TO COAL TREATMENT
SEPARATOR
DIFFUSER
AIR
LIMESTONE
COAL
EXHAUST HEAT
COAL TREATMENT
POWER
REJECTED SOLIDS
NOZZLE
HELIUM

Figure 50

Simplified Schematic of Closed-Cycle Liquid Metal MHD Topping Cycle Fired by Fluidized Combustor efforts are in early R&D stages, any energy balances are at best projections. Table 27 based on reference 5 provides a considered heat balance for an open-cycle MHD/steam generator plant. Diagrammatically, this can be illustrated by the heat flow diagram, Figure 51. It should be noted that both Table 27 and Figure 51 present overall system values and do not indicate intra-system energy transfers (e.g. employment of recovered heat). The overall heat balance assumes that electrical energy generated via steam would be produced at 1 kWh per 8160 Btu (reference 5). This is not an unreasonable projection when compared to the projection for the conventional steam-electric plant and taking into account differences in component makeup with associated energy loss values.

Table 27

Projected Heat Balance for Nominal 2000 MWe Open-Cycle MHD/Steam Plant

	Btu/hour (10^6 Btu's)	Percent of Total Energy Input
Net Electrical Energy Output	6,593.92	48.30
(MHD power 1420 MWe plus steam power 587 MWe less losses)		
Heat Rejected		
Cooling tower	4,589.80	33.62
Stack	1,171.34	8.58
Energy Consumed or Loss		
Additional energy input (for precipitator, seed recovery, Claus unit, etc.)	853.25	6.25
Coal ash and K_2SO_4 (sensible and latent)	109.22	0.80
Coal heating and miscellaneous	79.18	0.58
MHD inversion loss and auxiliary power requirements for coal handling, transformer loss, etc.	255.29	1.87
Total Energy Input	13,652.0	100.0
(Coal supplied 98.4%, correction for $SO_x \rightarrow K_2SO_4$ (G) condensation and solidification of K_2SO_4 1.6%)		

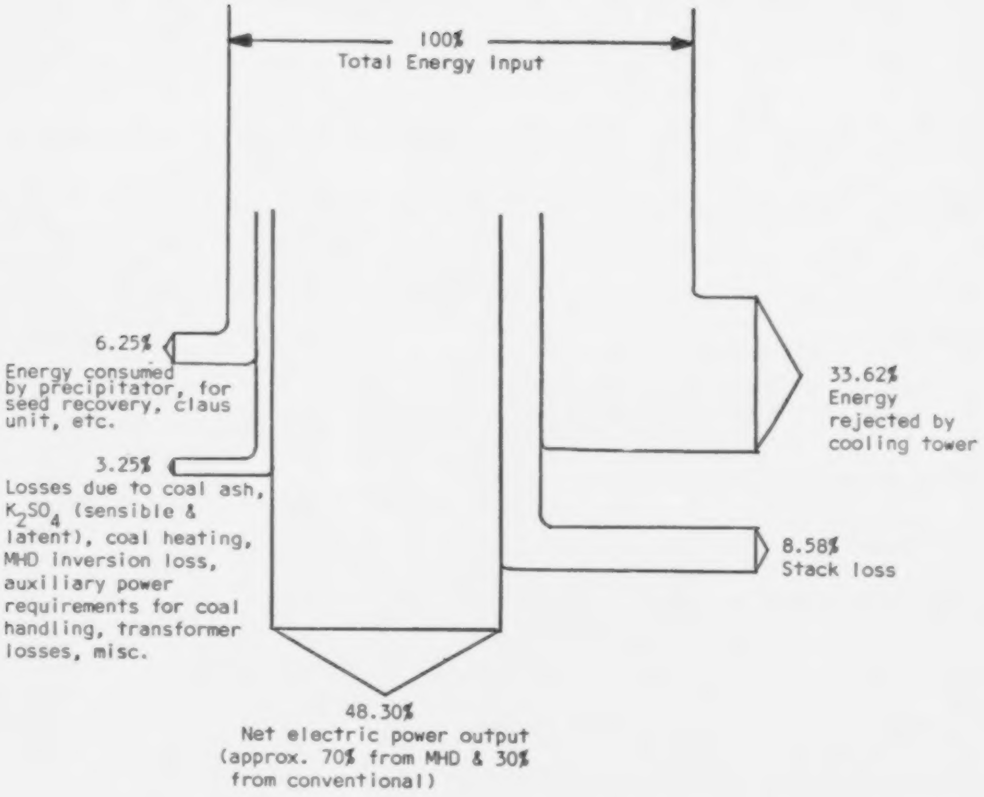
100%
Total Energy Input
6.25%
Energy consumed by precipitator, for seed recovery, claus unit, etc.
3.25%
Losses due to coal ash, K_2SO_4 (sensible & latent), coal heating, MHD inversion loss, auxiliary power requirements for coal handling, transformer losses, misc.
33.62%
Energy rejected by cooling tower
8.58%
Stack loss
48.30%
Net electric power output (approx. 70% from MHD & 30% from conventional)

Figure 51

Projected Heat Balance For Nominal 2000 MWe Open-Cycle MHD/Steam Plant

13.3 Applications

Current

At present, there are only experimental MHD working models in this country. The life expectancy of these models has been limited by the combined effects of current leakage, arcing between the electrodes, and the corrosive effects of high-temperature combustion gases and residues. Presently, there are major research, development, and testing programs at the component and subsystems level to alleviate these problems. This work is being sponsored by the Department of Energy with additional support from the Electric Power Research Institute and several utility companies.

The U.S.S.R. and Japan have also been quite active in the furtherance of this technology. In the U.S.S.R., an MHD pilot installation designated U-25, has been constructed and operated. The U-25 generator is rated at 20 MW nominal, and is gas fired. A smaller facility designated U-25B, which uses the same feed supplies and utilities as the U-25, has been used for joint U.S.-U.S.S.R. channel testing. The U.S.S.R. has announced the planning and design of the first large-scale commercial MHD/steam power plant of nominal 500 MW total capacity, with oil-firing. In Japan, an experimental oil-burning MHD generator with a 4 Tesla superconducting magnet has been tested at power levels of close to 500 kW, and other MHD system componenets have been studied on a small scale in an integrated component test facility. Other MHD development programs are currently in progress in Poland, Germany and India (3).

Projected

It is difficult to specify the role MHD will play in the future of domestic power generation. However, there has been a significant commitment of resources toward near-term goals (Fiscal 1979 DOE-MHD Budget was $80 million).

Specifically, the United States plans to have an operational pilot plant as early as 1985 and a base-load commercial demonstration before 1995 (2). Current plans call for this to be achieved in three phases (8) as follows:

1. Ongoing thru mid-1980's - development of engineering data and experience to design and build a 250 MW pilot plant--the Engineering Test Facility (ETF).

2. Running parallel with Phase I and on thru the 1980's - design, construction and operation of the ETF, a fully integrated combined cycle MHD/steam system operating at 250 MW, the minimum scale that can demonstrate the concept and still be of interest to utilities, and

3. During the mid- to late 1990's - demonstration of baseload power plant performance at several hundred megawatts using Commercial Demonstration Plants (CDPs).

Any large-scale commercial implementation of MHD combined-cycle power generation facilities will be in the post 2000 period.

13.4 Environmental Considerations

Because open-cycle MHD technology has been developed further than the closed-cycle plasma or liquid metal MHD technologies and since the DOE MHD program emphasizes open-cycle MHD, this discussion focuses primarily on the environmental concerns associated with open-cycle MHD. For closed-cycle systems under normal operating conditions, the effluents (e.g., SO_2, NO_x, hydrocarbons, CO, trace elements, particulates, ash residue, etc.) may be similar to those produced by conventional boilers and will not be discussed further (1).

Identified Pollutants

The range of pollutants from an MHD system is expected to be similar to the range of those associated with direct combustion processes. However, due to the extremely high temperatures required in the MHD process as compared to the relatively low temperatures of direct combustion technologies, significantly different relative amounts of the various effluents will be emitted. Due to the higher overall plant efficiencies of MHD power generation, less coal input is needed per unit of electrical output; therefore, pollutants (such as SO_2 emissions), thermal discharges, solid wastes, and their associated environmental impacts are expected to be less than those from a conventional coal-fired power plant of comparable generating capacity. However, sufficient experimental data are not available to verify this (1).

Air Emissions

Although fugitive emissions are a potential hazard to worker health and safety, the air emissions of primary concern are stack emissions. At the high temperatures intrinsic to MHD power generation, nitrogen oxide (NO_x) production is increased while the production of organic effluents, particularly the condensed polycyclic organic molecules (POM's) is decreased. The high temperatures also may alter radically the physical and chemical formation and the selective enrichment of various trace element compounds found in the fly ash particles. Because of the nature of sulfur-seed reactions unique to MHD processes, quantities of sulfur oxide (SO_x) are likely to be much lower in the effluents of an MHD facility than in those of a standard, commercial, coal-fired power plant (1).

An anticipated feature of the MHD power generator is a self-contained sulfur removal system inherent in its design. The potassium carbonate (K_2CO_3) seed used to increase the conductivity of the working fluid will combine with the SO_2 to form a sulfate or sulfite, which will be removed with the slag in the seed condensor and/or by particulate control devices. As stated earlier, experimental work has demonstrated SO_2 removal efficiencies from such seeding can exceed 99 percent for coal containing 2.2 percent sulfur by weight (6). Further studies have shown that the SO_2 content of emissions can be almost eliminated by increasing the seed rate, even using high sulfur coal which is environmentally unsuitable for use in conventional power generating plants (9).

The high-combustion temperatures of open-cycle MHD could produce up to ten times the nitrogen oxide (NO_x) emissions produced by conventional coal combustion (10, 11, 12). NO_x is a significant pollutant because of its direct effect on plants and animals and its role in the photochemical oxidant cycle. Thus, NO_x potentially presents the principal emission problem to be found in the MHD system.

Two methods of NO_x control have been identified: minimization of NO_x in the effluent gas, or maximization of NO_x in the effluent to recover nitrogen compounds (e.g., fertilizer). Presently, it appears that NO_x emissions will be controlled by the first technique through combustion modification. Combustion modification includes techniques such as initial fuel-rich combustion, down-stream adjustment of the fuel-air mixture to make it air rich (sometimes referred to as "two-stage air combustion"), and regulation of exhaust gas residence times in down-stream components to enhance decomposition of NO_x formation. According to data from the University of Tennessee Space Institute (UTSI) MHD test facility, NO_x emissions can be kept well below applicable standards by controlling the stoichiometric ratio and radiant boiler residence times (11). These data agree with data from earlier studies by others at Avco-Everett Laboratory (13). However, these data are in conflict with the Exxon computer modeling work. Their computer modeling of NO_x formation and decomposition in open-cycle MHD indicates that NO_x emissions may be near or above currently allowable limits (12).

It is expected that particulate matter existing in the exhaust gases will consist primarily of fly ash, with some unrecovered seed material (potassium carbonate and potassium sulfate). Due to the very high combustion temperatures characteristic of MHD, and possibly due to the effects of NO_x controls (14, 15), fly ash emissions from MHD are expected to consist of a greater proportion of fine particulate matter than those produced by conventional coal-fired power plants. These fine particles (<3 microns) may present a hazard to human health because they can enter and be retained in the lungs.

Emission of particulate sulfates, especially spent seed material, is a potential problem associated with MHD. Atmospheric sulfates have been implicated in such adverse environmental effects as acid rains, the modification of weather, visibility, and climate (1).

The environmental impacts of trace element emissions from a coal-fired MHD facility depend on coal quality, method of burning coal, power plant size and location, emission control technologies, and weather conditions (16). When coal is burned, the trace elements will 1) be trapped in bottom slag; 2) be collected in the emission control device as particulate ash; 3) escape through the stack as a gas or by adhering to effluent particles; or 4) escape as fugitive emissions within the facility environment. While a substantial fraction of trace elements present in the coal is retained with the fly ash and slag removed by control devices, significant quantities of trace elements still may be emitted as or on submicron-size particles because of collection inefficiencies in the small particle range characteristic of these devices. Potassium and radioactive compounds, as well as trace elements, adhere to the surfaces of particulates. Volatization of some trace elements during coal combustion and their release to the atmosphere in the gaseous phase also occur. Because of its characteristically high temperatures, this may be of particular concern in MHD.

Liquid Effluents

Effluents will result from boiler cleaning, cooling systems, and feedwater treatment processes which are not unique to the MHD technologies themselves, but exist in conventional boilers as well. Secondary water pollution can result from runoff and leaching from solid waste disposal sites if appropriate control measures are not taken. No data are currently available on the leachability of specific compounds and trace elements contained in MHD slag and fly ash. It is expected that the trace elements potentially found in MHD effluent streams and solid waste leachate will be similar to those identified for air emissions. Effluents resulting from MHD processes, seed regeneration, and solid waste disposal need to be characterized and assessed to ensure that they do not contain any unexpected hazardous pollutants or excessively high potassium levels, and that they will meet applicable water quality standards (17).

Solid Waste

A MHD facility, like any conventional coal-fired power plant, will produce solid waste. MHD-generated solid waste will be unique in several respects: 1) it will contain potassium compounds (K_2CO_3, K_2SO_4, and/or KOH) resulting from the injection of the seed material; 2) the slag collected from the combustor and other components will have different properties than bottom ash collected in conventional coal-fired systems; 3) fly ash collected in the emission control device probably will contain a greater proportion of fine particles; and 4) trace elements adhering to the surface of these fine particles may be more toxic to biological systems through leaching and fugitive dust emissions.

In order for open-cycle MHD to be acceptable both environmentally and economically, it is expected that the seed material must be recovered, probably regenerated, and recycled. The method has not been defined yet but the decision will affect both the quality and quantity of the solid waste generated from an MHD facility (1).

Regulatory Impacts

Since large-scale commercialization of MHD is planned for after the turn of the century, it is difficult to conjecture what the environmental regulatory climate will be for utility plants. In spite of the uncertain regulatory future and the final measurement and characterization of pollutants from MHD systems, it is generally agreed that because of its higher thermal efficiency, there will be less coal consumption per unit of electrical output and therefore, reduced emissions per Btu output than from conventional coal-fired generating facilities.

13.5 Performance

Current

Since there has yet to be a fully integrated MHD power generating facility, no actual performance efficiency has been measured.

Projected

Of all the emerging power generation technologies, MHD offers one of the most promising performance efficiency. Overall efficiencies of MHD-based systems (coal pile to electrical bus-bar) may exceed 50 percent as compared to 34 to 37 percent projected for conventional coal-fired plants with FGD now scheduled for construction (2). In practice, the coal-fired MHD generator will be installed as a topping system at the front end of a conventional steam turbine power plant, where it will draw off twenty percent of the coal's total energy. The hot exhaust gases will then be used to power the steam turbines, which will extract an additional 30 to 40 percent of the available energy. The total combined output (50 to 60 percent) is half again as much electrical power as that produced by today's conventional steam or nuclear power plants. Since coal-fired steam power plants currently supply about half of the nation's electrical energy (19), merely adding MHD as a topping system to existing plants could conceivably increase the nation's generating capacity by as much as 25 percent with the same fuel consumption.

13.6 Economics

Current

Since there are no commercial generation plants presently employing an MHD system in this country, a current figure for the cost per kilowatt hour of electricity is unavailable. However, detailed projections have been made of MHD costs and their behavior relative to conventional coal-fired plants beginning around 2000 when wide-scale implementation should occur.

Projected

Obviously, there is some measure of uncertainty associated with cost estimates for an emerging technology which is not even scheduled to go on-line until 1990. However, preliminary estimates indicate that in the 1990's, MHD-generated electricity will sell for around 32 mills/kwh as compared to about 45 mills/kwh for that from conventional coal-fired plants at that time (2). These estimates were based on theoretical plant configurations covered by the ECAS. Under their ground rules, capital costs were escalated by a combination of factors to the year construction would be completed if it had been started in mid-1975. The O&M cost component was based upon mid-1975 dollars and the fuel cost was based upon specified prices intended to project the period of consumption. Although many factors such as inflation rates and the period of implementation have changed substantially since that time, the relative cost advantage appears to be supported by more contemporary estimates.

Indications are that capital cost per kilowatt of installed capacity for an MHD topping system will be about the same as that for a conventional steam power plant in the latter 1990's. However, the operating costs per kilowatt may be significantly lower due principally to a more efficient utilization of fuel.

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